ONTARIO POWER AUTHORITY

2 Supply Mix Analysis Report

Volume 2 – December 2005

Ontario Power Authority

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Supply Mix Analysis Report

Volume 2 – December 2005

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2.1 What was OPA Asked to Do?

In this initial part of the analysis report, OPA outlines the Minister's request and its legislative contexts, the approach adopted by OPA in developing its response to the Minister, and the relationship of OPA's response to the next phase of planning, namely the development in 2006 of the Integrated Power System Plan (IPSP).

2.1.1 Key Findings

- Integrated Power System Plan (IPSP) is a 20-year plan that must be updated and approved on a three-year cycle, with approval received before the Ontario Energy Board (OEB)
- IPSP's rolling renewal dictates that the plan's purpose is to establish what needs to be done in the first three years from the picture found over the plan's 20 years
- OPA's task is to assess the available conservation and demand management (CDM), renewable and conventional resources in a manner that preserve options in the future
- IPSP's objective is to set in motion the range of initiatives required to meet Ontario's future electricity needs, recognizing that the plan is an evolving instrument
- Supply mix advice instructions are to consider CDM as a resource to be deployed before considering supply resources
- Renewables are to be treated not unlike CDM, to be established prior to consideration of conventional resources
- Conventional resources are to be determined after an examination of CDM and renewables: Conventional Resources = Total Demand + Required Reserves – CDM Resources – Renewable Resources

2.1.2 Introduction

This report provides advice to the Minister of Energy, the Honourable Donna Cansfield, on the future long-term electricity "supply mix" for Ontario. While it is the Ontario Power Authority's (OPA's) role to prepare an Integrated Power System Plan (IPSP), the Minster has the legislative authority to provide directives to OPA in the preparation of the plan. Prior to issuing directives to OPA, the Minister requested advice on the future supply mix for Ontario.

One of the primary functions of OPA is to plan for the future of Ontario's power system by integrating the broad array of industry, environmental and societal considerations, and make the necessary choices that can be put forward for regulatory approval. This advice to the Minister is a first step towards that new objective.

2.1.3 The Minister's Request and its Legislative Context

The supply mix advice flows from one of OPA's key objectives, which is to develop a 20-year IPSP for the province of Ontario. Guidance for the development of the plan is derived from legislation, regulations, ministerial directives and advice solicited from the Minister.

In general, the IPSP is expected to achieve goals established for the adequacy and reliability of electricity supply, including electricity supply from alternative and renewable energy sources and conservation, energy efficiency and demand management. The IPSP will also provide guidance for the development of Ontario's transmission system.

The purpose of the IPSP is to set a direction for the development of Ontario's electricity system. In this regard, OPA is mandated to consider a broad array of traditional and renewable generation, conservation, energy efficiency and demand management options.

2.1.3.1 Legislation

OPA's governing legislation is specific that the IPSP is to be developed with two priorities in mind. The first is that the plan be "designed to assist, through effective management of electricity supply, transmission, capacity and demand, the achievement by the Government of Ontario of,

- its goals relating to the adequacy and reliability of electricity supply, including electricity supply from alternative energy sources and renewable energy sources, and
- its goals relating to demand management".

The second objective is that the plan "encompasses such other related matters as may be prescribed by the regulations."

2.1.3.2 Applicable Regulations

The one regulation that has been approved to date with respect to the IPSP's development gives further detail to the task. Ontario Regulation 424/04 additionally requires OPA to:

- Identify and develop strategies to accelerate the implementation of conservation, energy efficiency and demand management
- Identify and develop strategies to encourage and facilitate competitive market based options for meeting overall system needs
- Identify measures that would reduce reliance on procurement contracts under Section 25.30 of the *Electricity Act, 1998*

- Identify factors that must be considered when determining that it is advisable to enter into procurement contracts under section 25.32 of the *Electricity Act, 1998*, and
- Ensure safety, economic, environmental sustainability and environmental protection

The regulation also dictates that the 20-year horizon for the IPSP commences in the year following its submission for approval to the Ontario Energy Board (OEB). Thereafter, the plan is required to be updated and submitted for approval every three years or as directed by the Minister or the OEB. OPA intends to submit its first IPSP to the OEB in June 2006.

2.1.3.3 Provision for Directives

Another factor that influences the development of the IPSP is ministerial directives. Under the legislation, the Minister of Energy "may issue, and OPA shall follow in preparing its integrated power system plans, directives that have been approved by the Lieutenant Governor in Council Cabinet that set out the goals to be achieved during the period to be covered by an integrated power system plan, including goals relating to,

(a) The production of electricity from particular combinations of energy sources and generation technologies;
(b) Increases in generation capacity from alternative energy sources, renewable energy sources or other energy sources;
(c) The phasing-out of coal-fired generation facilities; and
(d) The development and implementation of conservation measures, programs and targets on a system-wide basis or in particular service areas"

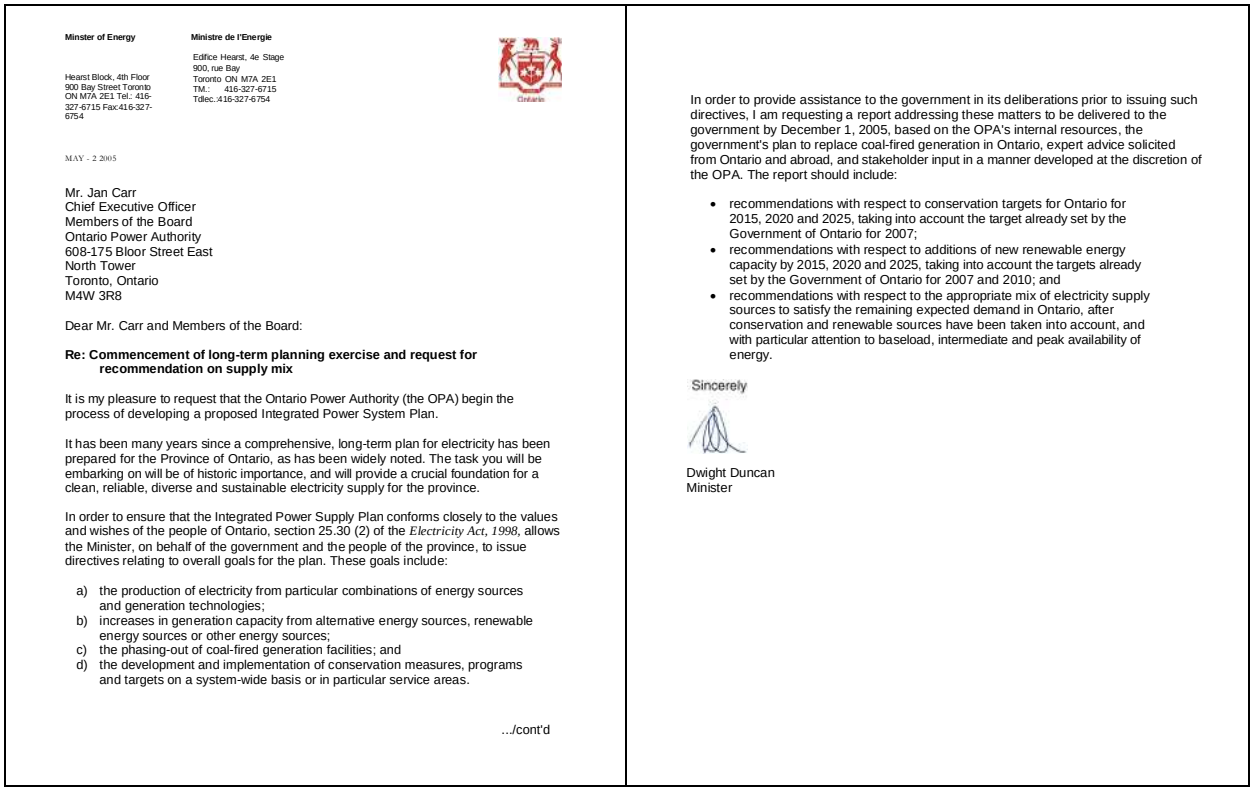
2.1.3.4 Guidance in Advice Solicitation

While OPA anticipates directives with respect to the IPSP, the Minister has asked for advice from OPA on the future "supply mix" for Ontario's electricity system. The purpose is to provide "assistance to the government in its deliberations prior to issuing such directives." In the May 2, 2005 letter to OPA (see Figure 2.1.1 below) requesting "supply mix" advice by December 1, 2005, the Minister is specifically seeking:

- Recommendations with respect to conservation targets for Ontario for 2015, 2020 and 2025, taking into account the target already set by the Government of Ontario for 2007;
- Recommendations with respect to additions of new renewable energy capacity by 2015, 2020 and 2025, taking into account the targets already set by the Government of Ontario for 2007 and 2010; and
- Recommendations with respect to the appropriate mix of electricity supply sources to satisfy the remaining expected demand in Ontario, after conservation and renewable

sources have been taken into account, and with particular attention to baseload, intermediate and peak availability of energy.

Figure 2.1.1 - Letter from the Minister



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Ontario

MAY - 2 2005

Mr. Jan Carr
Chief Executive Officer
Members of the Board
Ontario Power Authority
608-175 Bloor Street East
North Tower
Toronto, Ontario
M4W 3R8

Dear Mr. Carr and Members of the Board:

Re: Commencement of long-term planning exercise and request for recommendation on supply mix

It is my pleasure to request that the Ontario Power Authority (the OPA) begin the process of developing a proposed Integrated Power System Plan.

It has been many years since a comprehensive, long-term plan for electricity has been prepared for the Province of Ontario, as has been widely noted. The task you will be embarking on will be of historic importance, and will provide a crucial foundation for a clean, reliable, diverse and sustainable electricity supply for the province.

In order to ensure that the Integrated Power Supply Plan conforms closely to the values and wishes of the people of Ontario, section 25.30 (2) of the *Electricity Act, 1998*, allows the Minister, on behalf of the government and the people of the province, to issue directives relating to overall goals for the plan. These goals include:

a) the production of electricity from particular combinations of energy sources and generation technologies;
b) increases in generation capacity from alternative energy sources, renewable energy sources or other energy sources;
c) the phasing-out of coal-fired generation facilities; and
d) the development and implementation of conservation measures, programs and targets on a system-wide basis or in particular service areas.

.../cont'd

In order to provide assistance to the government in its deliberations prior to issuing such directives, I am requesting a report addressing these matters to be delivered to the government by December 1, 2005, based on the OPA's internal resources, the government's plan to replace coal-fired generation in Ontario, expert advice solicited from Ontario and abroad, and stakeholder input in a manner developed at the discretion of the OPA. The report should include:

- recommendations with respect to conservation targets for Ontario for 2015, 2020 and 2025, taking into account the target already set by the Government of Ontario for 2007;
- recommendations with respect to additions of new renewable energy capacity by 2015, 2020 and 2025, taking into account the targets already set by the Government of Ontario for 2007 and 2010; and
- recommendations with respect to the appropriate mix of electricity supply sources to satisfy the remaining expected demand in Ontario, after conservation and renewable sources have been taken into account, and with particular attention to baseload, intermediate and peak availability of energy.

Sincerely

Dwight Duncan
Minister

Whether directives are issued or not, the supply mix advice in this report will inform OPA's subsequent development of the IPSP. The IPSP, and OPA's work in developing supply mix recommendations, are intended to provide the path for ensuring the mid and long-term reliability and sustainability of Ontario's electricity system.

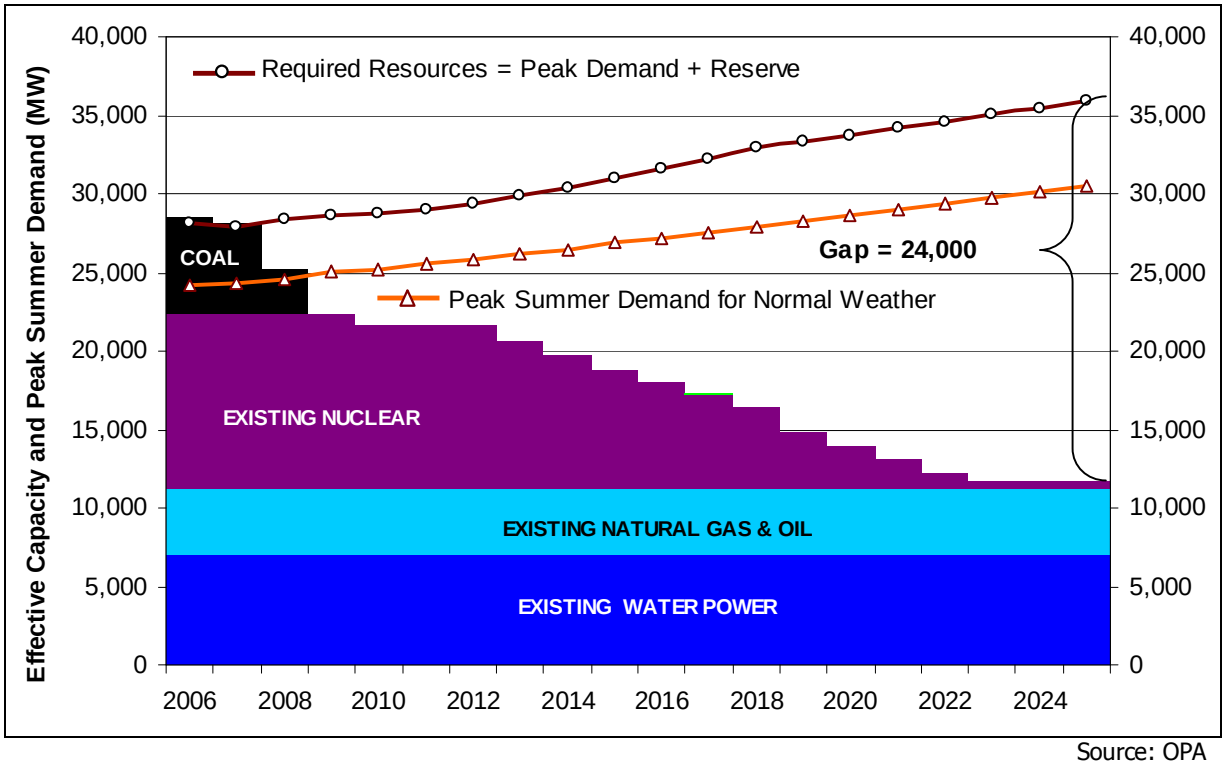
2.1.4 Supply Mix Challenge

The supply mix advice is of great significance because Ontario is at a critical juncture for its future electricity needs. This challenge stems both from the growth in demand and retirement of supply and the need for conservation or supply as a replacement. The potential for the resource gap, as shown in Figure 2.1.2, is approximately 24,000 MW.

In the period between 2005 and the end of the planning period for the IPSP in 2025, Ontario will need an additional 8,000 MW of conservation or installed capacity to meet growth in resource

requirements over current peak demand, with total requirements climbing to 36,000 MW from 28,000 MW. This figure is based on the peak continuing to grow (as in the IESO's *10-Year Outlook*), even at an already low rate of 1.3% per year. The number is a projection, and thus could be higher or lower. This growth on the demand side is only one dimension of the challenge facing Ontario.

Figure 2.1.2: Demand Growth and Generation Retirements Define Challenge



Source: OPA

In terms of existing supply, Ontario also faces an extraordinary challenge from retirements of nuclear stations and the replacement of coal-fired generation in Ontario. The province stands to lose close to 18,000 MW of generation capacity, which is 60% of the current total of 30,000 MW. This is represented by roughly 11,500 MW of nuclear and 6,500 MW of coal.

The graph in Figure 2.1.2, it should be noted, is the gross provincial picture. While it does suggest a cushion of excess supply until 2008, in fact there are transmission constrained local generation shortages in the Greater Toronto Area that must and are being addressed at present.

2.1.5 Approach Used in Developing Supply Mix Advice

In developing its supply mix advice, OPA has adopted a planning approach that recognizes the considerable uncertainties in long-term resource planning and the associated value of retaining flexibility and enabling options. While there is a need to ensure supply adequacy, OPA evaluates portfolios of supply sources and conservation options and evaluates them against criteria that have been developed in consultation with the public and stakeholders. The task has involved:

- Development of a long-term forecast of demand;
- Assembly of data and characteristics of individual conservation and demand management (CDM) and supply options, including renewable energy sources;
- Formulating various portfolios that balance supply and demand and evaluating them against criteria that include: cost, assessment of risk, environmental attributes, adequacy and reliability;
- Assessing the robustness of these portfolios under different scenarios, i.e. different ways in which the future may unfold; and
- Soliciting and incorporating the views of stakeholders

In performing these assessments and in the preparation of the supply mix advice, OPA has undertaken six exercises: Analytical Tools Development, CDM Options Analysis, Supply Technologies and Resources Review, Portfolio Analysis, Impact on the Natural Environmental and Sustainability Review, and Stakeholdering Consultations.

2.1.5.1 Analytical Tools Development

OPA developed analytical tools, including modelling tools and data for implementing a planning approach that focuses on assessment of risks, environmental attributes, cost, adequacy, and other characteristics of various portfolios. The purpose has been to develop detailed models applicable to Ontario's future demand and supply resource mix, and utilize these models to assess representative scenarios and portfolios that are developed and judged to meet criteria.

Given this is the early stage of its long-term planning, OPA's intention has been to focus on speed and flexibility in assessments rather than detailed models. OPA's has focused on assessment of those key risks that could affect portfolio performance, including financial, market, environmental and other quantifiable and qualitative risks.

In performing analysis, OPA assembled combinations of supply and demand responses (i.e. portfolios) to reflect system need and economic and environmental considerations. Risk analysis on these portfolios incorporated correlated risks among resource options. Analysis was also performed to test the robustness of these portfolios to different futures (i.e. scenarios). (see Parts

2.8 and 2.9 for the review and analysis of portfolios and scenarios, and Part 4.1 for the Report of Navigant Consulting).

2.1.5.2 CDM Options Analysis

OPA has developed a comprehensive assessment of different CDM (Conservation and Demand Management) options and associated risks. This task has been based on recent publications and source information from industry organizations, research and public agencies and developers. These portfolios were designed to reflect estimates of technical, economic and achievable potential, costs, implementation barriers, sector specific characteristics, experience in implementation of CDM, and technology developments.

OPA's assumptions include current government policy support of CDM, but recognize the potential for additional measures to be taken by government to achieve additional CDM. (See Part 2.4 for CDM initiatives in other jurisdictions, Part 2.5 for the CDM challenges in Ontario and Part 4.2 for the Report of ICF Consulting).

2.1.5.3 Supply Technologies and Resources Review

OPA has undertaken an assessment of different supply technologies and resources and associated risks, based on recent publications and source information from industry organizations, research and public agencies and developers. The assessment has included identification of capital and operating costs, performance characteristics, technology life-cycle, environmental impacts decommissioning costs and other relevant characteristics.

OPA considered the following in the Ontario setting: new natural gas generation, coal gasification (with and without CO_2 sequestration), nuclear (new and refurbished) and, based on Ministry of Natural Resources (Ontario) data and inventory, wind, biomass and hydroelectric resources. (See Part 2.7 for the technological characteristics and costs of supply resources and Part 4.3 for the report of CERI).

2.1.5.4 Impact on Natural Environment and Sustainability Review

OPA has undertaken analysis of methods to assess the impacts on the natural environment of generation options. The methods have been developed in a manner suited to long-term planning and are capable of capturing cumulative impacts and provide indications of the sustainability of options and supply mix plans. The intention has been to utilize methods that provide for identification and quantification of relevant environmental factors for assessment. (See Part 2.7 for the environmental implications of resource options and Part 4.4 for the report of SENES Consultants).

2.1.5.5 Consultations with Stakeholders

OPA has undertaken an extensive exercise of consultation with stakeholders. The purpose has been to ensure interested parties, including industry experts, market participants and groups representing consumers and the public interest, have their views taken into consideration. OPA's consultation process has included: soliciting written submissions from the public; soliciting expert industry, environmental and academic advice; conducting in-depth interviews with leading industry and non-industry influences; and conducting public opinion polling. (See Part 2.3 for an overview of what OPA heard and part 4.5 for the report of Decision Partners on the interviews and polling).

2.1.6 Observations

The CDM exercise undertaken by OPA for the supply mix advice differs from early CDM initiatives in Ontario and other jurisdictions. In this case, the assessment of supply resources will be considered only after the potential demand for resources has been examined and understood.

In a similar fashion, the instructions from the Minister of Energy request that the supply mix advice be constructed with the renewables treated not unlike CDM in the planning exercise. Where the CDM "resource" is to be constructed prior to the supply, so to are the renewables. Only after the CDM and renewables are assessed, are the conventional resources to be determined.

Conventional resources, as noted, are to be considered only after examination of CDM and renewables. This positioning of conventional resources can, in effect, be represented in the following equation:

Conventional Resources = Total Demand + Required Reserves – CDM Resources – Renewable Resources

The consequence is that the numbers for CDM and renewables become predetermined amounts and the conventional supply resources are what fill in the rest of the demand.

In preparing the IPSP in 2006, OPA's task will be to assess the available resources – CDM and supply, including renewable energy – and develop a plan that addresses the current need in a manner that preserve options in the future. The objective is to set in motion the range of initiatives required to meet Ontario's future needs, recognizing that the plan is an evolving instrument. The supply mix advice may be seen as the first step in this process.

2.2 Ontario Context for Supply Mix Advice

In this section, OPA examines the broader societal context for the electricity industry and how it is shaped by power system planning. The particular context areas considered are:[1] Demography, Geography and Natural Resources, Economy, Environmentalism, and Culture.

2.2.1 Key Findings

- A new equilibrium exists in Ontario where market forces and centralized planning co-exist; the reintroduction of planning in 2004 follows the introduction of a market framework in 2002, and its subsequent partial curtailment in late 2002
- Electricity's economic impact has been significant historically as "power at cost" facilitated private sector growth; the pragmatic consensus for public ownership became unhinged in the early 1990s
- Ontario has harvested its excess generating capacity since the recession of the early 1990s and developed a reliance on imports
- Population alone dictates a very large electric system in Ontario; the Golden Horseshoe is forecast to have 71% of total population in 2025
- Demand growth increased 7% per year, on average, through to the 1960s
- Capital spending on nuclear in 1970s was $1.5 billion per year with an economic multiplier of 1.5 – a *de facto* industrial strategy – but stagflation meant the policy was not sustainable; Ontario Hydro's 1989 "demand-supply" plan included a large nuclear station, but the recession intervened
- Waterpower and uranium from Canadian Shield were critical for power generation; inter-connection of transmission within Ontario in the 1950s made it possible to develop the waterpower of northern Ontario for use in the south; after all large waterpower sites had been exhausted by the 1950s, coal fired generation was adopted as an interim measure, nuclear power became the dominant source of generation
- Early environmentalism sought to manage natural resources for public good; post-war human welfare ecology addressed societal impact; deep ecology focuses on value of non-human life independent of human needs and purposes; the challenge of power system planning is to balance the societal consensus for renewables with these other environmental concerns

[1] The context development has been aided by the understanding of Ontario developed by Rand Dyck, Professor Emeritus, Laurentian University, Sudbury, Ontario.

2.2.2 Introduction

Electricity systems do not exist in isolation from their societal, environmental and economic context. Ontario's electricity past was certainly developed in this context – successes and failings – and its future supply mix and long-term planning must be shaped in the same way with the benefit of new considerations, including technological advancements.

The supply mix exercise has convinced OPA that power system planning overlaps with a number of aspects of public policy in Ontario. While such overlap certainly makes power system planning more complex, at the same time it truly opens the door to smarter solutions that benefit Ontarians in more than one area. An example of such a "win-win" solution would be utilizing organic waste as fuel for electricity generation. These and other public policy aspects would include waste management, parks and land use policies, and municipal planning.

2.2.3 Demography and Electricity

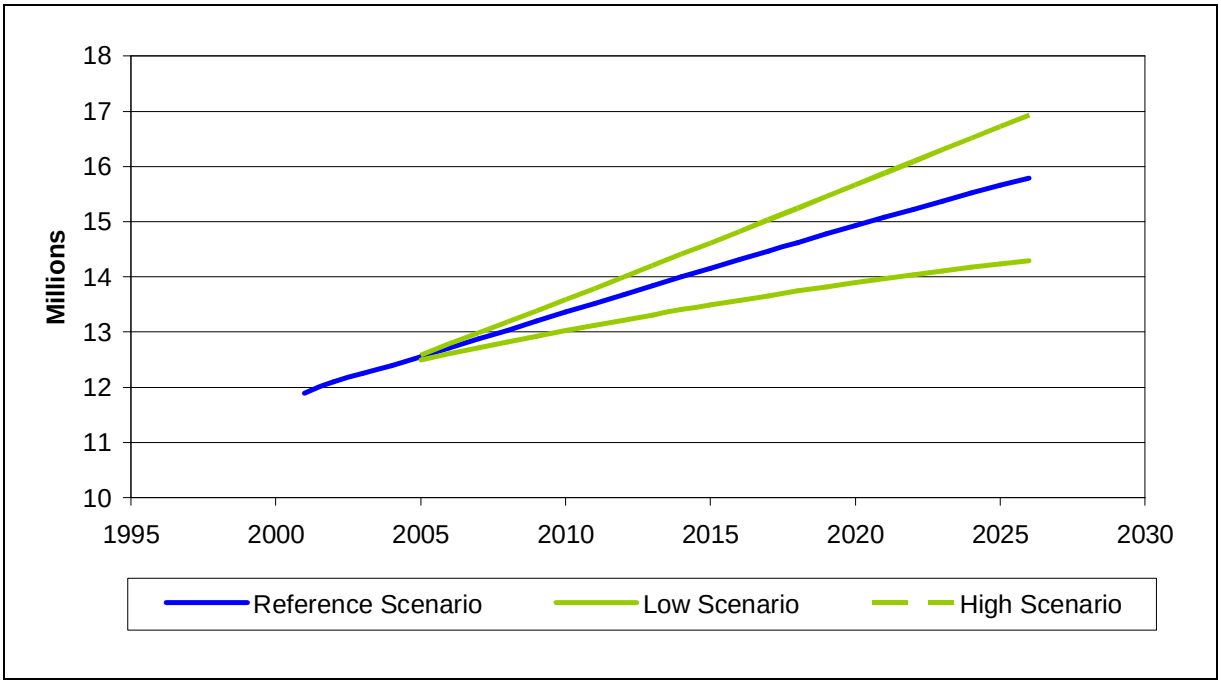
Ontario's population alone dictates a very large electric system by Canadian and other comparisons. With the population expected to grow by 25% over the period to 2025, there are a number of implications for electric power planning system. In addition to overall population growth, the changing character of the demography is also of significance. The main issues are overall population growth, urbanization, relative urban size and distribution and rural decline.

Overall Population Growth: Now 12.5 million (2005) and approaching 40% of the Canadian total, Ontario is the largest and fastest growing province in Canada. Provincial government estimates suggest Ontario's population will reach 15.8 million by 2025 – a 25% increase. This involves growth of 1.2% annually in the decade to 2011, 1% in the decade to 2021 and 0.8% in the decade to 2031.[2] The level of the growth is seen from the following figure to be comparable to that of past decades. This growth clearly will tend to create the need for additional power system resources.

Increasing Urbanization*:* The urbanization phenomenon means the growth in demand will not be uniform. Some regions, especially in southern Ontario, will experience growth in demand significantly above the provincial averages, with rates of demand on the power system also exceeding average growth. The experience in the Greater Toronto Area (GTA) and the Greater Golden Horseshoe is striking compared to the rest of the province, including other urban areas. As it stands right now in 2005, there is a supply shortage in downtown Toronto and the western GTA.

[2] Ministry of Finance, *Ontario Population Projections, 2004-2031*, February 2005; Ministry of Finance, *Ontario Demographic Quarterly, First Quarter 2005*; and Ministry of Finance, *Towards 2025: Assessing Ontario's Long-term Outlook* (2005).

Figure 2.2.1: Ontario Population Projections



Note: Reference Scenario based on historical data

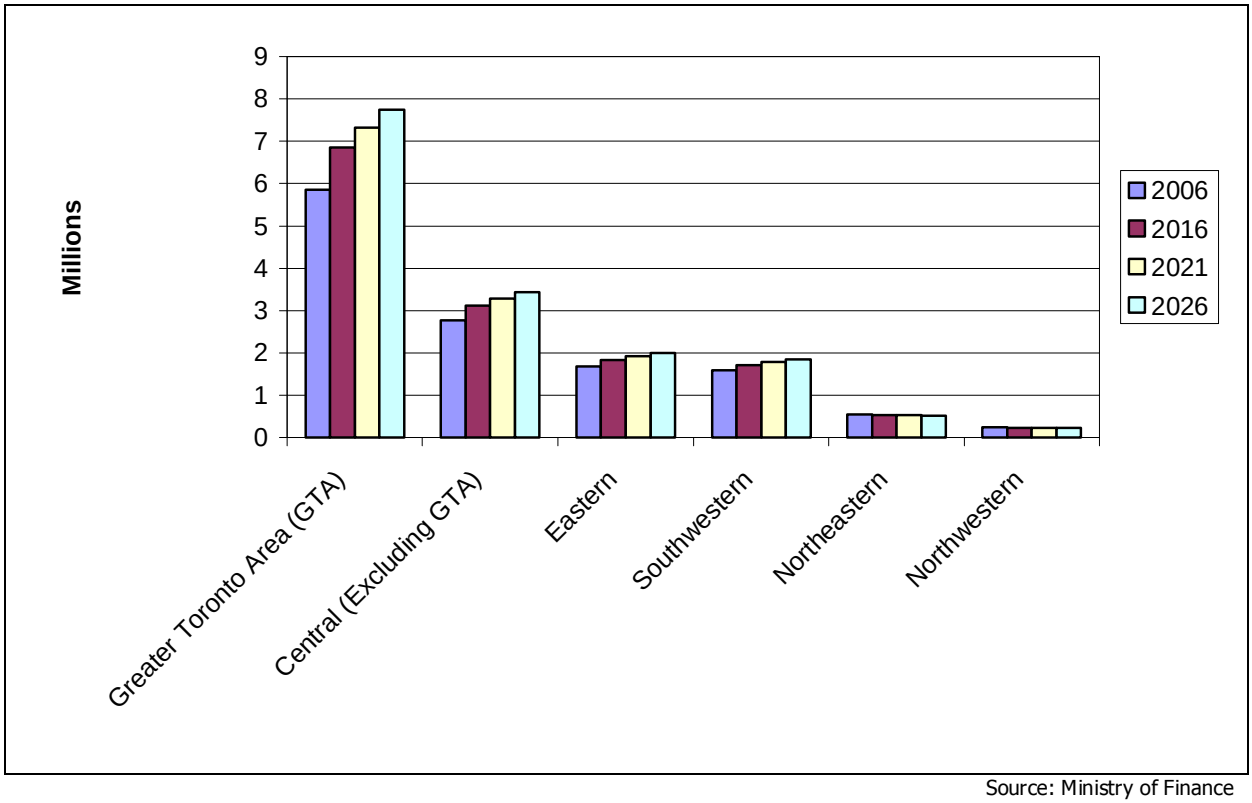
Source: Ministry of Finance

By 2025, the GTA alone (Toronto and the regional municipalities of Durham, Halton, Peel and York) will be home to more than half of all Ontarians. It is now 5.7 million people and 45.6% of Ontario's population (2004). This is up from 42% in the 1991 census and is expected to reach 49% and 7.8 million by 2025. Growth in the GTA is 1.8% annually, which is 50% above the growth rate of the province as a whole.

The Greater Golden Horseshoe, which is the planning area for the province's recent *Places to Grow Act, 2005*,[3] is forecast to contain 70.9% of the province's population in 2025, up from the current level of 67.5%. In addition to the GTA, this area includes the highly developed communities in Hamilton and Niagara and the outer-ring larger urban communities in Brantford, Cambridge, Kitchener, Waterloo, Guelph, Barrie and Peterborough, not to mention lesser-populated urban centres such as Orangeville, Lindsay and Cobourg.

[3] *Places to Grow Act*, 2005 (S.O. 2005, chapter 13).

Figure 2.2.2: Population Projections, Ontario Regions



Source: Ministry of Finance

The implication of this urbanization trend for electricity planning is that location of generation and demand resources in and near to the Golden Horseshoe and the GTA becomes increasing attractive as a means of minimizing infrastructure (transmission) upgrades. This in turn suggests the selection of options that can be sited where needed.

Relative Urban Size and Distribution: Unlike other provinces, which tend to have one or two large population centres and large rural expanses, Ontario has regional centres spread across much of its geography. Indeed, there are now more than a dozen Census Metropolitan Areas in Ontario with more than 100,000 people, including Greater Sudbury and Thunder Bay in northern Ontario. The consequence is that the electric load in Ontario, while concentrated in the largest areas, is still spread out, especially in the industrial centres of southern Ontario.

Decline in Rural Ontario: The final demographic issue is the rural-to-urban and northern-to-southern shift in population, which in many areas represents a net decline. The consequences are disheartening, but also raise possibilities. Where rural and small town Ontario may lose the growth needed to finance the infrastructure it requires to sustain itself, the connection of renewable resources in rural Ontario could be a welcome infusion of new economic activity related to connection facilities and other infrastructure.

2.2.4 Geography, Natural Resources and Electricity

The three very diverse physical features that characterize Ontario's landforms have had strong influence on the electricity system. These features are:

- Great Lakes and St. Lawrence Lowlands
- Canadian Shield
- Hudson Bay Lowlands

By where they live and work in "southern" Ontario, most Ontarians are familiar with the Great Lakes and St. Lawrence lowlands, which proved highly suitable for the early agricultural development of the province and its later urbanization and industrialization. This area has large hydroelectric generation on the Niagara, Ottawa and St. Lawrence rivers. It also has significant potential for wind-generated electricity, especially on and in areas near the shores of the Great Lakes.

Where "northern" Ontario starts – always a keen matter of debate for other policy matters – is clear in terms of geography. It is distinguished by the second key feature of Ontario's geography, which is the Canadian or Precambrian Shield. The Shield, which runs from the Ottawa Valley north of Ottawa in the east through to the Manitoba border in the west, running through central Ontario (north of Barrie) at the Severn River. The Shield area has been critical to the development of much of Ontario's early and continuing wealth, including the vast amount of waterpower and uranium deposits available for electricity generation.

The third key distinguishing feature of Ontario's geography is its Hudson Bay lowlands, which form a separate watershed from the Great Lakes-St. Lawrence basin. Being the most remote and northerly portion of Ontario, and not having the resource advantage of the Canadian Shield, it has played less of a role in shaping the electric system in Ontario. In addition, it has not had the role of Quebec's Hudson Bay shore, such as the Great Whale projects, because it lacks the same vertical drop. It has, however, significant potential area for wind resources.

The natural resource character resulting from Ontario's geography has had a significant influence on the make-up of the electric industry and the shape of the economy the electric system has been developed to serve. Beyond the initial agricultural development of the province, in the 20th century the new economic development "staples" – forestry, mining and hydroelectric power – were in abundance and were critical to the province's growth.[4]

In southern Ontario, advances in transmission technology at the turn of the 20th century made it possible to transport the "white coal" of Niagara's waterpower to the emerging manufacturing

[4] H.V. Nelles, *The Politics of Development: Forest, Mines and Hydro-electric Power in Ontario, 1849-1941* (Toronto: Macmillan, 1974).

centres driven by the second industrial revolution.[5] Ontario's abundance of hydroelectricity was particularly advantageous because, while the developments had a high capital cost, their low operating costs and unlikelihood of being overtaken by technological invention, provided Ontario with comparatively inexpensive electricity. Within decades, however, all of the large waterpower sites in southern Ontario on the Niagara, St. Lawrence and Ottawa rivers had been harnessed, and many of the smaller sites on lesser rivers.

In northern Ontario, the location of the forest and mines, the early development of hydro-electric power aided in the development of a resource extraction and processing rather than manufacturing-based economy. Among the significant mining discoveries in northern Ontario was in fact uranium, whose processing made it a resource for the generation of nuclear power. The interconnection of transmission systems within Ontario, most fully in the 1950s, also made it possible to develop the waterpower of northern Ontario for use in southern Ontario.[6]

After all the "large" waterpower sites had been exhausted by the 1950s, Ontario set its sights on a nuclear-powered future. The attractiveness of nuclear was that, like hydroelectricity, the effect of the large capital cost was more than offset by a resource fuelling cost.

The difference was that where the hydraulic force of the water was the motive power in hydroelectricity, the thermal effect of fission was the motive power for nuclear. In the result, nuclear was advanced as a suitable addition to waterpower as a base-load (continuous) source of electricity generation – a portion of a consumption curve that is always required.

Before it could proceed to develop nuclear power commercially, Ontario needed to develop other thermal power, namely coal, in the period of transition. The absence of coal as an indigenous natural resource had in fact constrained the economic development of Ontario in an earlier era, and indeed had created resentment from the reliance on imported coal for generating electricity. Moreover, since the characteristics of coal were high operating cost (price of the fuel) and low capital cost (relative to hydroelectricity and nuclear), its role in Ontario was better placed as peaking / intermediate resource.

2.2.5 Economy and Electricity

As a jurisdiction, Ontario would have faired well economically even without the beneficial effects of low-priced electricity. The province has been favourably blessed by climate, resources, a protectionist national policy that promoted it as an industrial heartland to a western hinterland. It has also enjoyed proximity to U.S. markets, the last of which became of increased importance in subsequent "national policies" of continentalism and free trade. The impact of

[5] Ibid.; Neil B. Freeman, *The Politics of Power: Ontario Hydro and its Government, 1906-95* (Toronto: University of Toronto Press, 1996).
[6] Jean Manore, *Cross-Currents: Hydroelectricity and the Engineering of Northern Ontario* (Waterloo: Wilfrid Laurier University Press, 1999).

electricity in Ontario's economy has nonetheless been significant for how the province's economy progressed within this already advantaged framework.

In the early 1900s, the early years of the electric industry's development, the for-profit structure of the industry and reliance on imported coal had made electricity an expensive commodity. In turn, this structure hampered the diffusion of the technology and impeded the "second" industrial revolution – based on electricity and the internal combustion engine – economic growth occurring elsewhere.

However, the turnaround to a "power at cost" system early in the last century under the company that became Ontario Hydro launched a facilitative growth role in the economy. Indeed, the "at-cost" structure was thought to have rapidly diffused the technology in urban and rural areas of Ontario compared to other jurisdictions.[7]

With this framework in place, electricity's impact on the economy came from both the low price cost input and the rapid diffusion of new technology for electricity usage. The advantage that was said to have resulted from this framework is that it led to the full utilization of the infrastructure, which increased revenues and led to the justification for additional infrastructure. And with supply having always to keep up with demand, a continuous loop of exponential growth was the result.[8] Except for during the Great Depression, demand always grew substantially, and increased 7% per year, on average, through to the 1960s.[9]

Following the Great War, the impact of the electric industry began to be felt in a significant way through its capital spending impact to the economy. When it entered generation development by building the then largest hydroelectric station in the world, Ontario Hydro had become a major influence in the economy.

In the period through to the 1960s, this impact was refined through massive expenditures for generation developments on the St. Lawrence and Ottawa rivers, subsidized frequency standardization to bring the various Ontario Hydro systems together at 60-Hertz power – the new north American standard, whereas the Niagara system was 25-Hertz – and province-wide integration of transmission facilities into a single grid. Ontario Hydro had become representative of what the British came to call the "commanding heights" of the economy.[10]

[7] Keith Robson Fleming, *Power at Cost: Ontario Hydro and Rural Electrification, 1911-1958* (Montreal and Kingston: McGill-Queen's University Press, 1992).
[8] The suggestion has been made that the era was one of "progress without planning". Ian M. Drummond, *Progress Without Planning: The Economic History of Ontario from Confederation to the Second World War.* (Toronto: University of Toronto Press, 1987).
[9] Royal Commission on Electric Power Planning, *The Report of the Royal Commission on Electric Power Planning.* (Toronto: Queen's Printer for Ontario, 1980).
[10] Freeman, op. cit.

In the post-war era, Ontario Hydro's impact on the economy, in effect, was crafted into a *de facto* nuclear industrial strategy. Where other provinces and jurisdictions were pursuing their own "mega-projects" as local industrial development strategies – oil in Alberta, potash in Saskatchewan, hydroelectricity in Quebec, as just a few examples – against the bulwark of a new world of international commerce, Ontario participated fully.

All the pieces of an Ontario nuclear industrial strategy were in place through marshalling the operating and construction strength of Ontario Hydro, AECL's CANDU nuclear technology, centred in Ontario, uranium mined at Elliot Lake, Ontario, and the manufacturing base in Ontario for "nuclear class" components such as boilers made in Cambridge, Ontario.[11]

Coincident with the oil crisis in 1973, Ontario Hydro's impact on the economy was solidified even further. It was at this time that the province approved the major nuclear expansion for the second stations at Pickering and Bruce and the authorization to proceed with the preliminary work on the Darlington station. By the end of the 1970s, the Porter Commission determined the impact of Ontario Hydro's capital spending to be $1.5 billion per year with an economic multiplier of 1.5.[12]

The problem, however, was that recession and inflation – stagflation – had devastated the economy and, while the capital spending was serving a counter-cyclical function for the government, the situation was not sustainable. Ontario now had approximately 40% excess capacity of electricity and, with the Darlington station incomplete, interest rates in excess of 20%, the completion date was pushed into the future rather than continue with construction.

In the late 1980s, Darlington was approaching completion and plans for another large station were forwarded through Ontario Hydro's 25 year "demand-supply" plan.[13] However, when the economy went into recession in the early 1990s following the introduction of North American free trade, Ontario Hydro withdrew its plan that had been submitted for approval to the province's Environmental Assessment Board.

In the ten years since coming out of recession, Ontario has harvested the excess capacity that had been built up in the system and developed an increased reliance on imports. With the opening of electricity markets in other jurisdictions and the declining economies of scale in generation through new technologies, policy developments soon led to the demise in Ontario of centralized planning of electricity, and through it the economy. The movement to competitive

[11] This thinking is consistent with Ken Rea's view that the post-war Ontario economy witnessed "a growing acceptance of government intervention in economic life and intense interest in the mechanics of economic control." K. J. Rea, *The Prosperous Years: The Economic History of Ontario, 1939-1975* (Toronto: University of Toronto Press, 1985). For seeds of the nuclear story, see: Paul McKay, *Electric Empire: The Inside Story of Ontario Hydro* (Toronto: Between the Lines, 1983); and, Paul McKay, *The Roman Empire: The Unauthorized Life and Times of Stephen Roman* (Toronto: Key Porter Books, 1990).

[12] Royal Commission on Electric Power Planning, op. cit.

[13] Ontario Hydro, *Providing the Balance of Power: Ontario Hydro's Plan to Serve Customers Electricity Needs* (Toronto: Hydro, 1989).

markets for provision of generation followed with the *Energy Competition Act* in 1998 and the opening of the market to wholesale and retail competition for the commodity portion of the industry in 2002.[14]

But the pendulum has now swung back once more – a new hybrid form of planning has re-emerged and with it comes the potential to make electricity resource decisions that meet broader economic objectives.

2.2.6 Environmentalism and Electricity

Environmentalism and electric power have a curious history, and one that, surprisingly to some, have not always been in conflict in Ontario. Indeed, the relationship of the environment and the electric system in Ontario has, arguably, progressed through "conservationism", "human welfare ecology" and "deep ecology".[15]

Early public ownership of the electric industry in Ontario – which was justified on the perceived demerits of private development – had a very close link with the late 19th century conservationist movement. The objective was to manage natural resources for the benefit and use of all. Indeed, Ontario Hydro's motto, transcribed from Latin, was "the gifts of nature are for the people". In many respects, Ontario Hydro's rational and planned development of waterpower was perceived to be an embodiment of the public good over private exploitation.

Environmentalism came into conflict with power systems development in post-war Ontario with the rise of the human welfare ecology, which had detached itself from conservationism's connection to economic progress. This new concern for the aesthetic value of the environment was, in the eyes of some, a beneficiary of post-war prosperity's release of the individual from concerns for physical and economic security.

In Ontario, the new ecology movement had an important effect on the direction of power system planning in late 20th-century Ontario. While it may not have been thought of as an environmental issue, the negative public reaction to Ontario Hydro's planning and construction of new 500 kV transmission lines around Toronto was a seminal moment. The new lines raised the issue of balancing interests when routes were questioned and aesthetic concerns were raised. This could be said to be the point when Ontario Hydro no longer was an unquestioned embodiment of the public good.

While the human welfare ecology movement continues, the concept of deep ecology has placed a new focus on the value of non-human life independent of human needs and purposes. This is

[14] For one view on this development, see: Jamie Swift and Keith Stewart, *Hydro: The Decline and Fall of Ontario's Electric Empire* (Toronto: Between the Lines, 2004).
[15] This review of environmentalism has benefited from the work of Mark O. Dickerson and Thomas Flanagan, *Government and Politics*, 4th edition (Toronto: Nelson, 1994).

of very significant relevance to current issues for electric power planning, especially sustainability. The basic premise holds that the interference with the non-human world is excessive and worsening and that humans, through effects such as emissions from power generation, should not have the right to reduce the richness of the environment and its diversity.

Deep ecology raises interesting and challenging philosophical questions for environmentalists and power system planners as current challenges are confronted. For instance, there is a general societal consensus that renewable energy resources, such as wind and small hydro, are desirable. However, there is disagreement regarding the hard choices of siting small hydro and wind generation in specific locations.

On water power, there are sites within provincial parks which, in an earlier era, conservationism would have permitted. Indeed, the first contracts for power development at Niagara were issued by the precursor of the Niagara Parks Commission, whose task was to preserve the beauty of the falls. Currently, some of the best small waterpower sites in Ontario are in conservation preserves, which have deep ecology constraints that impede their use.

Wind power has similar challenges. Some of the best sites in southern Ontario are on the Niagara Escarpment, which since the rise of human welfare ecology has been protected for its aesthetic value. While wind farms are thought to leave a very small footprint, there is concern within the Audubon community with bird deaths.

The challenge of environmentalism for power system planning is acting on the societal consensus for more renewable energy in a manner that meets other societal objective respecting human welfare and ecology.

2.2.7 Political Culture and Electricity

Electricity has in fact shaped the socio-political culture in Ontario through the general phenomenon of modernization, and this culture has in turn shaped the development of the industry through pragmatic responses to industry structures and challenges. It would not be incorrect to suggest that electricity was so entwined with perceptions, if not reality, of the public good in Ontario that, until the 1960s, to oppose its development or suggest there were "limits to growth" was heretical. Indeed, during the land assembly for the head-pond flooding required from damming the St. Lawrence in the 1950s, some of the original United Empire Loyalist communities in Ontario were relocated.

In this regard, Ontarian's attitudes to electricity were typical of the "operative norms" of the culture, including the pursuit of economic success, managerial efficiency and balancing of

interests.[16] While paradoxical to many, the striking feature of 20th-century Ontario's electricity development was the extent of public acceptance for government ownership, essentially to facilitate growth in the private economy. Indeed, after an initial battle that saw the owners of manufacturing interests not side with the financial interests behind private power production, a political consensus for public ownership was unchallenged until the end of the century. As long as the industry was well managed and providing for economic success, the province was pragmatic about ownership.

The seeds of a change in attitudes to the consensus, as noted above, began with reaction to construction of 500 kV transmission lines to move the large volumes of nuclear power coming on stream around Toronto and southern Ontario. In response, the province appointed a commission on rights-of-way planning in 1972.[17] The recommendations led to broader incorporation of public views in the planning and siting of electricity infrastructure, generation and transmission included.

During this same period, significant public and legislative opposition arose to the nuclear power buildup that had begun in 1973. A healthy skepticism was developing in Ontario, as it was in other jurisdictions in the new inherently unstable economic times, for the ability of a government agency to manage large business enterprises. While the economic underpinnings of the nuclear buildup were not spoken of as an industrial strategy, Ontario Hydro was moving into unprecedented territory for economic planning.

In response, the government appointed a royal commission on all aspects of electric power planning, not just transmission. The conclusions and recommendations blazed the path for conservation and demand management.[18]

An implication of the recommendations was that supply planning, in the expectation that demand would always catch up, was now flawed. While Ontario Hydro continued to 1998, it never did recover its perception as an embodiment of the public good. Moreover, since economic instability did not permit it again to find its bearings as a facilitative instrument, it suffered as well in perception of its managerial efficiency and its ability to promote economic success. The consequence was that the political culture consensus forged in 1906 to create Ontario Hydro had come unhinged.

While the experiment with competitive markets was not the success that was expected, the political culture could be said to have arrived at a new consensus through the report of the

[16] Sid Noel, "The Ontario Political Culture: An Interpretation," in Graham White, ed., *The Government and Politics of Ontario*, 5th ed. (Toronto: University of Toronto Press, 1996).
[17] Solandt Commission, *Interim Report*, 1972; *Report of The Solandt Commission: A Public Inquiry Into The Transmission of Power Between Nanticoke and Pickering*, 1974; and, *Report of the Solandt Commission: A Public Inquiry Into The Transmission of Power Between Lennox and Oshawa*, 1975.
[18] Porter Commission, op. cit.

Electricity Conservation and Supply Task Force (ECSTF) in 2004.[19] The ECSTF essentially called for the creation of an agency to conduct long-term planning and to be a "champion" of conservation. Following this recommendation, the government created the Ontario Power Authority to perform these (and other) functions.

2.2.8 Conclusion

Currently, then, the politics of power in Ontario have reached a new equilibrium in which both market forces and centralized planning co-exist. The new centralized planning, while it does not have the command and control role of Ontario Hydro, nevertheless must develop plans based on the broad public good. The parties providing the new resources will, however, be fully commercial entities, not crown agencies. It remains to be seen how the equilibrium will shift over the next 25 years. The answer may well have implications for the planning decisions made over the period, for example, whether the public will be willing to assume the risks of new generation technologies or large-scale capital-intensive options such as nuclear plants.

[19] ECSTF, *Tough Choices: Addressing Ontario's Power Needs*, Final Report to the Minister. (January 2004).

2.3 What Did OPA Hear from the Public and Stakeholders?

This section is a summary of the advice and comments received from stakeholders that informed the development of the supply mix advice. Stakeholder consultation consisted of four parts: public submissions; industry, environmental, and academic expert presentations; in-depth interviews and public opinion polling.

2.3.1 Key Findings

- Advice and comments were received from the public and stakeholders over several phases of supply mix consultations , including 185 written submissions, 30 industry, environmental and academic expert presentations, in-depth interviews with stakeholders, and public opinion polling were undertaken
- Public submissions provided OPA with advice regarding appropriate criteria to consider in analytical approaches to planning, approaches to conservation and demand management (CDM), generation resources and technologies for the supply mix and appropriate methods to assess impacts on the natural environment
- Industry, environmental and academic experts provided OPA advice on contributions from various supply resources, policy barriers to new generation development, transmission and connection barriers, electricity price signals, areas for energy efficiency savings, risks associated with certain supply resources, and the state of several new technologies which may impact the supply mix over the supply mix planning horizon
- In-depth interviews and public opinion polling reinforced several findings from other consultation activities, including the importance of availability and reliability as drivers of the supply mix, environmental responsibility and sustainability as key decision criteria, as well as the challenges of implementing current plans to replace coal-fired generation
- Public and stakeholder consultation assisted OPA substantially in addressing planning and supply mix challenges, documenting public policy challenges and developing approaches for balancing public and private interests in the supply mix, in addition to providing a solid foundation for moving forward in 2006 to develop the integrated power system plan (IPSP)

2.3.2 Introduction

The Ontario Power Authority (OPA) accomplished a significant and valuable degree of stakeholder consultation in developing its supply mix advice. In the development of the Integrated Power System Plan (IPSP), additional stakeholder input will be required through a process that will follow the present exercise. The IPSP will also require formal approval through

an Ontario Energy Board hearing. The OPA recognizes that dialogue with the Ontario public is an important and valued contribution shaping its work. The stakeholder consultation process that OPA has undertaken is as follows.

Public Submissions: OPA issued a call for public submissions on supply mix advice in July 2005 that was solicited both through OPA's website and local, regional and national newspaper advertisements. OPA received 185 submissions and more than 200 documents from a wide range and representation of groups and individuals. These have been reviewed and are now posted on OPA's website. A discussion of what was heard follows in Section 2.3.3.

Industry, Environmental and Academic Expert Presentations: When all the public submissions were reviewed and considered, OPA addressed gaps in information not available from submissions through invited presentations from industry, environmental and academic experts. The experts were asked to prepare briefings on subjects specified by OPA or relating to their particular concerns regarding the supply mix. All told, OPA heard 30 presentations, for which only a few presenters requested confidentiality. In addition to the formal presentations, OPA met with stakeholders and groups on a consistent basis throughout the supply mix project. The presentations are available on OPA's website and a discussion of what was heard follows in Section 2.3.4.

In-depth Interviews: The complexities of determining supply mix advice also led OPA to entertain consulting proposals for assistance with its stakeholder activities. OPA utilized the firm of Decision Partners Inc. to undertake in-depth interviews with 27 industry stakeholders and 35 non-industry societal influencers. The results provided OPA with an assessment of people's beliefs and preferences in relation to electricity supply and issues. The report by Decision Partners is posted on OPA's website (Part 4.5) and Decision Partners has written Section 2.3.5.

Public Opinion Polling: In addition to the interviews, Decision Partners also conducted public opinion polling research on behalf of OPA. The poll of approximately 800 Ontarians was undertaken to assess their views and the differential from the values and beliefs of those interviewed. The findings confirm that the two groups hold similar values. The polling is discussed in the Decision Partners report and in Section 2.3.5.

The results of the consultations with stakeholders have enriched the supply mix advice substantially. The following sections present a summary of each phase of the stakeholdering process.

2.3.3 Public Submissions

The call for public submissions on supply mix advice was solicited both through OPA's website and through advertisements in both English and French language in local, regional and national

newspapers. OPA received 185 submissions from a wide range and representation of groups and individuals. The text of the call for written submissions is reprinted in the box below and the list of newspapers is provided in the Appendix (Section 2.3.6).

CALL FOR WRITTEN SUBMISSIONS (NEWSPAPERS)

The Ontario Power Authority (OPA) was established in December 2004. OPA has as one of its mandates long-term power system planning for Ontario.

Under the Electricity Act, the Minister of Energy may issue directives with respect to the overall goals of OPA's long-term planning. The Minister has requested advice from OPA on the future "supply mix" for Ontario prior to contemplating directives.

OPA invites written submissions or comments from all interested parties to aid in its preparation of the advice. The Minister's request of OPA specifically includes:

- Recommendations with respect to conservation targets for Ontario for 2015, 2020 and 2025, taking into account the target already set by the Government of Ontario for 2007;
- Recommendations with respect to additions of new renewable energy capacity by 2015, 2020 and 2025, taking into account the targets already set by the Government of Ontario for 2007 and 2010; and
- Recommendations with respect to the appropriate mix of electricity supply sources to satisfy the remaining expected demand in Ontario, after conservation and renewable sources have been taken into account, and with particular attention to base-load, intermediate and peak availability of energy.

Please visit OPA's website www.powerauthority.on.ca/ to view more of the supply mix project, including OPA's "issue areas" for preparation of the advice to the Minister and the Minister's letter to OPA.

Submissions or comments must be submitted to OPA by August 26, 2005 by email to supplymixsubmissions@powerauthority.on.ca or by mail.

The newspaper placement directed interested parties to OPA website for additional information pertaining to the supply mix project and a more detailed account of the types of advice OPA was seeking. Specifically, OPA was seeking advice according to four "issue areas" as outlined in the detailed call. Portions of the detailed call for written submissions are reproduced as follows.

DETAILED CALL FOR WRITTEN SUBMISSIONS (WEB POSTING)

OPA Approach to Supply Mix

OPA will be developing a planning approach that recognizes the considerable uncertainties in long-term resource planning. OPA's approach will focus on explicit assessment of risks and exposure and recognition of the value of flexibility. The prospective approach will develop and evaluate different portfolios of supply sources and conservation options. The approach will then evaluate the portfolios against criteria that will be developed in consultation with stakeholders.

OPA Issue Areas for Supply Mix

OPA has identified four 'issue areas' where advice from interested parties would be especially helpful:

- Appropriate analytical planning approaches that focus on assessment of risks, environmental attributes and cost characteristics of various portfolios. The approaches will be of the greatest value where they include assessments of the risks that could affect portfolio performance, including financial, market, environmental and other quantifiable and qualitative risks.
- Appropriate approaches to constructing CDM ("Conservation and Demand Management") portfolios for inclusion in long-term plans. These approaches will be of the greatest value where they include established data on technical and achievable potential, costs, implementation barriers, sector specific characteristics, experience in implementation of CDM, and technology developments.
- Assessments of different supply technologies and resources in the Ontario setting, including (but not limited to) natural gas generation, coal gasification, nuclear (new and refurbished), wind, biomass and hydro-electric resources. The assessments will be of the greatest value where they (1) utilize recent source information or current data on capital and operating costs, performance characteristics, technology life cycle, environmental impacts and any other relevant characteristics and (2) present data on a consistent basis across the supply technologies and resources that would be suitable for planning studies.
- Appropriate methods to assess the impact on the natural environment of supply options. The methods will be of the greatest value where they are: (1) methodologically suited to long-term planning; (2) provide for identification and quantification of relevant environmental factors for assessment; (3) capture the cumulative environmental impacts; and (4) provide indications of the sustainability of options and supply mix plans.

Written Submissions on Supply Mix

OPA invites written submissions or comments from all interested parties on the Minister's specific requests and OPA's 'issue areas', both as outlined above.

OPA encourages interested parties to structure their submissions and comment based on the four issue areas identified by OPA.

2.3.3.1 Overview of Submissions

OPA received submissions from a diverse cross-section of Ontarians, ranging from individuals, citizens' groups, industry associations, to corporations. The breakdown of the 185 submissions, according to their source, is as follows:

Table 2.3.1 – Summary of Supply Mix Submissions

Source	Number of Submissions
Individuals	100
Single companies (including consultants)	27
Trade associations	31
Environmental groups and organizations	8
Citizens groups and cooperatives	5
Labour unions and workers' groups	5
Regulatory and/or government agencies	3
Academics	4
First Nations	2

Source: OPA

As might be expected in a public submissions process, a variety of viewpoints were represented. While some embodied a single statement, several presented detailed responses to one or more of the four issue areas as requested by OPA. No matter whether the issue areas were specifically addressed by the respondents, the content of all submissions was reviewed and considered in the preparation of the supply mix advice.

The sections below present a summation of the perspectives and advice that OPA heard from the written public submissions. Since it would not be possible to document the wide range of viewpoints and breadth of the advice received in a summary document, interested readers are directed to OPA website (www.powerauthority.on.ca) for a full listing of the public submissions. Only a few respondents requested that their submission not be posted publicly, and some submissions included copyrighted material, which could not be posted.

2.3.3.2 Issue Area 1

Advice on appropriate analytical planning approaches that focus on assessment of risks, environmental attributes and cost characteristics of various portfolios.

OPA heard numerous suggestions regarding planning and analytical approaches that could assist in developing long-term plans for the provincial power system. Submissions focused largely on suggested criteria to consider in planning approaches, rather than analytical planning approaches, tools or models themselves. Among the factors that OPA was advised to consider in its suite of analytical approaches were the following:

- Fuel supply reliability
- Fuel price volatility
- Environmental and health risk factors
- International agreements (such as the Kyoto Accord)
- Risks associated with overbuilding capacity and estimating future demand
- Cost-reflective pricing
- Impacts of market interventions
- Internalization of external costs, and
- Addressing knowledge and data gaps with respect to electricity supply, transport and use.

Some submissions suggested that OPA utilize a specific analytical approach or model. Life-cycle assessment, in which a "cradle to grave" approach is taken toward evaluating and comparing the costs and impacts of different supply options, was suggested by several submissions. Other specific models or analytical approaches were suggested, as well as recommendations regarding model characteristics. For example, one respondent recommended that OPA select assessment methodologies which allow for flexibility of changing assumptions throughout the modeling timeframe.

Among the submissions, there was widespread support for integrated resource planning (IRP) approaches to planning Ontario's power system. Individual submissions emphasized different aspects of IRP, including: balancing supply with demand, prioritizing conservation and demand management, supply diversity, flexibility, utilizing renewable sources of energy, promoting small-scale and distributed generation resources, and accounting for regional differences in province-wide planning.

Also reflected in several submissions was the need for Ontarians to pay the "true cost" of electricity, with some suggestions that OPA examine methods to build in "externalities" such as health care costs and environmental damage into the price of electricity (i.e., to internalize costs). From supporting advanced, or "smart" metering technologies, to graduated electricity rate structures, stakeholders delivered a clear message to OPA, that the price of electricity must reflect its true cost.
Some notable suggestions were also made regarding gaps in knowledge with respect to electricity supply technologies, social and environmental impacts of the power system, performance of large-scale integration of renewables and intermittent supply sources, as well as the necessary technical expertise required to build and maintain the future power system. One submission recommended OPA address such knowledge gaps by partnering with academic institutions, while another suggested that OPA invest in ongoing research to address these deficiencies.

In general, the advice provided by the many stakeholders supported evaluating a full range of alternatives and incorporating them into planning analyses, including new generating capacity,

power purchases, energy conservation and efficiency measures, cogeneration and district heating and cooling applications, and renewable energy sources.

2.3.3.3 Issue Area 2

Advice on appropriate approaches to constructing conservation and demand management (CDM) portfolios for inclusion in long-term plans.

As a whole, the submissions confirmed to OPA that conservation needs to be a vital component of the supply mix plan. Several submissions argued that conservation and demand management (CDM) should be a top priority of the supply mix plan. Others felt that such initiatives represent "a mitigating factor only and not a replacement for new supply to meet growing needs". The former view is reflected in the sentiment that robust end-use technologies could permit energy savings of 25% by 2020, while the alternate view was represented by some proponents of large-scale generation technologies. A clear polarization on the potential and costs of CDM measures was reflected in the different views on appropriate roles for CDM in the province.

A segment of the public feels that "cost-effective" CDM initiatives are always worthwhile to pursue. One submission included a report which concluded that the average cost of energy efficiency (EE) programs was significantly less than the costs of base-load and intermediate generation resources, based on experience in California ($29.50/MWh for EE vs. $58/MWh for base load; $118/MWh for intermediate; and $167/MWh for peaking generation resources). Other submissions reflected the environmental benefits of CDM, with one respondent stating that energy efficiency is the "supply option" with the least environmental impact.

A basis for several submissions from individuals and environmental groups was found in the joint submission from the Pembina Institute and the Canadian Environmental Law Association (Pembina/CELA). It used the Canadian Integrated Modeling System (CIMS) developed at Simon Fraser University to conclude that CDM measures could lead to reductions in peak demand (MW) of 50% compared to the IESO forecast and reductions in energy consumption (TWh) of 40% compared to a "business as usual" scenario by 2020. What OPA heard throughout the stakeholder consultation process was that there is much more to be learned about CDM and its maximum potential to mitigate new supply requirements in Ontario.

OPA also heard that it is far from alone in its mandate for CDM. Multi-faceted, broad-based, and multi-year campaigns, as well as coordinated and consistent public education programs, were recommended for effective energy conservation and energy efficiency across Ontario. Local distribution companies (LDCs), municipalities, energy services providers, educational institutions and purveyors of myriad technologies all have a significant part to play in the effective and aggressive pursuit of CDM in Ontario.

The willingness of municipalities to work with OPA in implementing its vision and celebrating the successes of CDM was related in a submission representing the views of municipalities. A Net-Zero Housing initiative was also advocated as a means to achieving CDM targets, which includes targets for homes with zero net consumption for heating and electricity, by utilizing passive solar construction, energy efficient design and appliances, and renewable energy systems. The key role of local distribution companies (LDCs) was also highlighted among the submissions. The provision of financial incentives to CDM program providers was listed as important for the development of the CDM market. The notion that LDCs should be accountable to deliver a certain threshold of demand reduction, subject to receiving fixed incentive payments, was also listed as a precursor to CDM success.

Applying appropriate analytical approaches to forecasting demand growth was also brought to OPA's attention. Warnings against over-estimating future demand growth were present in some submissions, and one submission suggested questioning the fundamental assumptions underlying growth forecasts as a means of reducing risks associated with over-estimating future demand.

Several submissions reflected the notion that Ontarians must be accountable for their own responsible use of electricity. Graduated rate structures, in which those using more, pay more per unit electricity, were advocated, as well as more draconian measures such as placing upper limits on per capita electricity consumption in the province. Above all, receiving accurate, real-time price signals reflective of the true cost of electricity was noted as a necessary precursor to effective CDM in Ontario.

Other submissions addressed non-prescriptive approaches to CDM portfolios, hardware solutions such as advanced metering technologies, as well as the feasibility of web-based software technologies to manage demand loads of consumers.

2.3.3.4 Issue Area 3

Advice on assessments of different supply technologies and resources in the Ontario setting, including (but not limited to) natural gas generation, coal gasification, nuclear (new and refurbished), wind, biomass and hydro-electric resources.

One of the most common themes among the supply mix advice submissions was that Ontario needs supply from a diverse mix of power sources. However, the recommended form of such diversity varied considerably among the submissions. These viewpoints ranged from urging OPA to keep all potential sources of power "on the table", to looking to alternative, less conventional, and even more expensive resources, while replacing coal-fired generation or nuclear power. Every plausible supply resource was advocated in one or more submissions; likewise, every supply resource had its detractors.

System reliability was defended as a social good in one submission, which also argued in favour of policies or regulatory prescriptions for a "minimum diversity of supply". A prevalent viewpoint was to base reliability on a reasonable diversity of generation technology and location, with access to imports and adequate transmission.

Some submissions provided more specifics on the form of diversity. Consideration of diversity among different regions of the province, through the development of diversified resource portfolios for each region that would provide each region with flexibility in meeting future change was one elaboration of the concept. The intrinsic value in small, decentralized and geographically diverse grid-connected projects was also emphasized. Specifically, the benefits of such diversity were described as including the following:

- Improved system efficiency
- Reduced line losses
- Load displacement
- Reduction of transmission constraints
- Regional disbursement of benefits
- Increased capital from local sources
- Increased tax revenues, and
- Greater flexibility in reaching renewable goals

In addition to supply diversity, a number of specific generation types and technologies were advocated among the submissions. The following sections deal more specifically with generation supply and technology options addressed in the supply mix submissions.

Generation from Renewable Sources of Energy

There was a general consensus that sources of renewable energy should be systematically developed in Ontario over the next 15 to 20 years. There was considerable disagreement, however, as to the degree to which Ontario should, or could, build renewable sources of electricity into its generation portfolio.

A significant number of submissions from individuals reflected the recommendations of Pembina/CELA, that OPA consider in its analysis a scenario of 60% of electricity from renewables by 2020, along with a complete replacement of coal and nuclear generation in the province. Many of these submissions appeared in response to an e-mail lobbying initiative of the Ontario Clean Air Alliance (OCAA). This recommendation, however, was in stark contrast to other submissions which argued that renewable energy supplies will contribute very little to Ontario's overall supply requirements.

Other areas of concern relating to renewable sources of energy included the intermittent and non-dispatchable nature of wind and solar resources, the need for back-up generation associated with wind and solar resources, uncertainty regarding grid impacts of large amounts

of grid interconnected, small-scale renewables, as well as the high costs of renewable generation relative to conventional sources of power. OPA learned that the public is well informed of the various challenges facing the future development of the power system, including many issues associated with integration of renewable supply technologies into the grid.

Among the submissions calling for more aggressive approaches to renewables were recommendations for standard offer contracts (SOCs), also known as feed-in mechanisms or advanced renewable tariffs. SOCs are guaranteed payments, either in the form of a fixed price or a premium price (per kWh) made to renewable electricity generators either independent of, or in addition to, the market price of electricity. SOCs represent one type of alternative payment structure for renewables such as solar photovoltaics, as renewables have different cost structures than fossil stations, i.e. renewable facilities have a much higher ratio of fixed to operating costs. Noted among the submissions was the fact that the greatest level of activity on renewable electricity has occurred in those countries with feed-in tariffs (SOCs), and that such mechanisms are preferable to rebates, due to lower transaction costs and bureaucratic requirements.

Renewable sources of electricity were also cited as a priority in the more remote northern regions of the province. Submissions reflecting the regional concerns of the north pointed to the demonstrated opportunities as well as growing interest in developing renewable energy generation systems in the north, including water, wind, biomass, and solar power. Submissions reflecting northern regional viewpoints also highlighted several barriers to renewable generation development in northern Ontario. Incidentally, several of these policy barriers also preclude the development of many renewable generation projects in southern Ontario as well. The creation of provincial parks and protected areas around many potential waterpower sites, financial and policy barriers to grid interconnection of renewable generation projects, lack of transmission corridors near potential renewable projects, as well as the number of separate approval processes facing new projects, were submitted as significant barriers to the development of new renewable projects.
In general, the range of views regarding the development of renewable generation projects converged on the fact that incremental additions of renewables to Ontario's supply mix, no matter how large, can offer system and societal benefits. One submission provided a succinct summation of such by stating that "small renewable energy projects dispersed across the province may offer the benefits of distributed generation, pump more of the project development dollars through rural economies, increase public awareness and acceptance of renewable energy, and provide a stable domestic market for renewable energy technology that can spur regional manufacturing industries".

Generation from Natural Gas

There was a wide range of views on the degree to which natural gas should be used for electricity generation. Some respondents pointed to natural gas as the only suitable transition fuel that could move Ontario away from coal and nuclear generation toward a completely

renewable system, while others pointed to the risks associated with price volatility, future availability and greenhouse gas concerns with natural gas.

The apparent disconnect between power generation planning and the realities of natural gas transportation and distribution infrastructure was highlighted by one submission which represented the views of large natural gas users. A projected increase of 17% over current average Ontario demand for natural gas by 2008 for new electricity generation raised the question of who will pay for the investments in supply, transport, distribution and storage of the gas.

Future prices and price volatility of natural gas were concerns raised in several submissions. One voice critical of the use of gas for electricity generation expressed doubt that the fuel would ever again be priced low enough to justify its routine use as base load generation. The same submission went on to recommend that natural gas never be deployed as a base-load fuel source in non-CHP generators. This position was repeated by others who recommended that if natural gas is to be used to generate electricity it should only be used in cogeneration (combined heat and power, or CHP) cycles.

To the contrary, other submissions highlighted the ability of natural gas to advance the Ministry of Energy's desire for diversity of supply, from a CDM perspective. A perspective from a gas distribution company suggested that switching customers from electric appliances to natural gas appliances (space heating, dryers, water heaters) in a targeted 5-year plan could reduce peak load demand by 1490 MW.

As well, several submissions pointed to natural gas as the fuel of choice in transitioning toward a power system more heavily based on renewable sources of generation, and pointed to the fuel as a means of alleviating much of the air quality burdens associated with other conventional sources of generation. Conversely, other submissions noted that producing larger amounts of electricity using natural gas as a fuel source carries significant burdens from a greenhouse gas perspective, and that using natural gas to transition toward a renewable generation system would do nothing to help in meeting Canada's commitment to the Kyoto Protocol.

Generation from Coal

Coal was another subject of considerable debate among the supply mix submissions. Support for the government's replacement of coal-fired generation in Ontario was prevalent among the submissions. Allusions to the health burdens of the air pollution caused by coal-fired generation were also common among the submissions.

On the other hand, several submissions argued in favour of retaining coal as a generation option in Ontario. Support for coal-fired generation, however, was generally qualified with suggestions for the use of best available emissions control technologies or advanced coal technologies such as integrated gasification combined cycle (IGCC) technology. Other

submissions recommended that coal assume a peaking generation role for the foreseeable future, in addition to utilizing existing and emerging advanced coal burning technologies to increase efficiency of combustion, reduce emissions, reduce carbon intensity of the fuel, and capture and sequester GHGs. Another submission went further in suggesting that Ontario reduce coal to a backup power source only, as a means of increasing emphasis on new intermittent sources of power, such as some renewables.

It was also suggested that the consideration of environmental emissions should not be limited to within Ontario's borders, especially with respect to the replacement of Ontario coal plants. One recommendation was that environmental performance calculations should include effects of "any scenario that would result in significant imports of electricity", as they often originate from coal-fired plants with limited emissions controls.

With respect to the use of "clean coal" technologies, there appeared to be a range of conceptions as to what constitutes clean coal among the submissions. Some submissions referred to Lambton generating station's units 3 and 4, having been retrofitted with selective catalytic reduction and flue gas desulphurization technologies, as clean coal. Others referred to emerging technologies such as IGCC as clean coal. Others suggested that there is no such thing as clean coal. It is apparent that, given the range of technologies available, that the public would benefit from the transfer of more information regarding the range of technologies available, in the development of the IPSP.

Generation from Nuclear Energy

The "no nuclear" viewpoint prevailed among the submissions from environmental groups and those that reflected the OCAA or Pembina/CELA points of view. A few submissions were staunchly against any new build or nuclear refurbishment program in the province. For the other viewpoint, several submissions advised OPA to consider next generation nuclear as a supply option in Ontario. Some nuclear technologies that were mentioned among the submissions were the Advanced CANDU Reactor (ACR), General Electric's (GE) Advanced Boiling Water Reactor and GE's Economic Simplified Boiling Water Reactor. On the other hand, a few submissions warned against the consideration of Ontario as a testing ground for unproven nuclear technologies, both from reliability and safety standpoints.

There are clearly different views on the future role of nuclear energy in the province, as well as different and opposing views regarding particular nuclear technologies.

Other Technologies, Tools and Supply Options

Several other specific generation technologies were also advocated among the submissions. These included advanced biomass anaerobic digesters, micro-sized, combined heat and power units using a variety of fuels, pumped storage hydroelectric generators with "spinning reserve"

capacity, fuel cells, and integrated gasification combined cycle (IGCC) technologies, in addition to conventional generation technologies.

While the incorporation of specific generation, transmission, or demand management technologies into the supply mix plan was advocated in several submissions, many of these submissions were made by the developers or purveyors of the technologies themselves, by industry associations, or by academics. Among the technologies brought to the attention of OPA were high-efficiency transformers, power flow controllers, power invertors, advanced metering technologies and web-based electricity demand management software.

2.3.3.5 Issue Area 4

Advice on appropriate methods to assess the impact on the natural environment of supply options.

The linkages between energy and the environment were a common theme underlying the supply mix submissions. One respondent stated that issues of electricity are necessarily also issues of the environment. While concerns for the environment ran high among the public, advice on appropriate methods to assess impacts on the natural environment were sparse.

One submission suggested that a criterion for a supply mix strategy should be the continual improvement in per-unit environmental performance over time, and an absolute reduction in environmental impacts over the planning period. Others were of the opinion that environmental objectives needed to be given at least equal consideration with economic objectives in long-term planning. Some submissions recommended that OPA consider Canada's Kyoto commitments in the supply mix plan, as well as highlighting the environmental benefits of renewable supply technologies and successful CDM programs.

From the public submissions it is clear that regard for the environment and sustainability is a high priority for Ontarians. While submissions acknowledged that environmental considerations must be balanced against other objectives, such as system reliability and cost criteria, both the necessity and challenge of incorporating environmental aspects into the planning process were reinforced.

2.3.3.6 Conclusion

A wide variety of viewpoints was reflected in the over 180 responses to the call for written submissions, representing a range of disparate views and interests from across the province of Ontario to interested parties in other jurisdictions. Several common themes emerged from the submissions, as well as many points of contention among the Ontario public. The most commonly expressed points among the submissions were that Ontario needs a diverse supply

of electricity, must pursue conservation and demand management, and must grow the share of renewable sources of electricity in the province. Natural gas, coal and nuclear sources of energy have both supporters and detractors, and all generation technologies found an advocate from the submissions. Integrated resource planning, technologies, policies and regulations, and analytical models were all suggested as tools to assist OPA in creating a plan for Ontario's long-term electricity supply.

The submissions, while providing a feel for the varied stances of the Ontario public on issues of supply diversity, CDM, generation technologies and environmental and sustainability criteria regarding the supply mix, left OPA with many questions for experts with knowledge of issues of electricity supply, transport and use, as well as environmental aspects of the power system. This need was addressed in a second phase of stakeholdering, described in the next section.

2.3.4 Industry, Environmental and Academic Presentations

OPA solicited expert advice from industry, environment and academic experts and formally invited these stakeholders to make *in camera* presentations to OPA.

In addition to specific technical questions put to each expert, OPA asked for insights on the important strategic factors to consider in arriving at supply mix recommendations, and also asked them to address specific issues and concerns related to Ontario's electricity supply mix. In total, 30 presentations were made individuals having a wide range of areas of expertise, over a four-week period in September and October 2005. The breakdown of the 30 presentations, according to their constituency, is as follows.

Table 2.3.2 – Summary of Supply Mix Presentations

Source	Number of Presentations
Individual companies (including consultants)	4
Trade Associations	9
Environmental groups, energy "think tanks"	8
Labour unions and workers' groups	1
Regulatory and/or government agencies	5
Academics	2
First Nations	1

Source: OPA

The following sections represent a summary of comments from a very diverse range of interests. Therefore, some recommendations may be in direct contradiction to others. Many of the stakeholders made copies of their presentations available for posting on OPA's website at http://www.powerauthority.on.ca/.

2.3.4.1 Issue Area 1

Advice on appropriate analytical planning approaches that focus on assessment of risks, environmental attributes and cost characteristics of various portfolios.

Most parties tended to make recommendations on the issues OPA should consider in planning Ontario's electricity system, as opposed to actually providing advice on appropriate tools or planning models themselves. One party did provide information about a consultant whose model produces a "back cast", i.e., starting from a future target state, the planner works backwards towards the present day, and sets targets and timelines along the route from now to that future state. For that particular presenter, the picture of the future would include little or no environmental impact, economic opportunity for Ontarians, and a secure local supply.

OPA was reminded that the core to this planning exercise is the need for supply adequacy. Reliability and sustainability were common themes throughout almost every presentation. Presenters emphasized the need for OPA to ensure enough capacity for normal demand plus sufficient reserves to cope with unexpected peaks in demand or shortfalls in supply. Many parties asked us to place the highest priority on the measures needed to ensure reliability of supply, and linked reliability to energy diversity.

Many parties told OPA to conduct an assessment of risks, reliability, environmental attributes, including sustainability, and cost characteristics of various portfolios. A key message from many parties was a need for provincial self-sufficiency and Canadian self-sufficiency, and not to rely on U.S. supply.

OPA was urged in its planning to allow a commercial market to exist but to steer a course through it via a strategic plan. Several parties presented a rationale for central planning, with long lead times, and suggested that OPA will have a long lasting role in planning.
OPA was reminded that facility siting matters in planning, and one presenter was supportive of OPA targeting specific locations for generation plants. The difficulty of obtaining new sites gives existing sites tremendous value, and so OPA was urged to ensure valuable site assets were retained for use in the power system. Regarding policies to do with siting, placing transmission facilities underground, with right-of-way issues, etc., some presenters commented that community standards should not introduce resistance every time the same issues arise, an example being the effects of electromagnetic force emissions (EMF). Adopt similar principles and standards province-wide so that there will be no need to debate over and over again, was a message that was heard.

OPA was warned that it might have to design its plan, then select the proponent(s), then select the contract, then select the site; that is, OPA may need to be very prescriptive in this plan.

One party suggested there is an argument for downtown Toronto having different reliability standards from other cities and towns, since the risks and benefits are greater for Toronto from

an outage. This is not unlike the method for planning for New York City, which is paid for by the city itself and not the whole New York system. Questions were asked about whether rules should allow one community to have different reliability standards than others. Allowing communities to have choices, and recognizing these differences with different pricing, was forwarded as an option.

Pricing

OPA was told that it is no easy matter to determine what is a fair price for power; and that reliable, safe and clean power comes at a cost. There are no short cuts and consumers need educating about this, too. One party claimed that Ontario needs higher electricity prices in order to promote conservation and increase the standard of living; higher prices will lead to increased productivity and make society better off. Increased electricity prices were a benefit because they might drive low wage jobs out of the industry and instead support a high wage economy. The suggestion was that low-priced electricity is not a pre-requisite to support high economic growth. Another presenter asked OPA to ensure that low income households are not left worse off by higher electricity prices.

Other parties reminded OPA to ensure supply choices do not undermine Ontario's manufacturing competitiveness versus that of neighbouring regions. One party listed stable and affordable prices as a critically necessary component to OPA's plan. However, OPA also heard that Ontario seems to have some price headroom compared to neighbouring U.S. markets which tend to have more expensive power.

Several parties noted that in order to encourage the needed investment in energy infrastructure, cost-reflective energy prices are essential at the least. OPA was reminded of the importance that both consumers and investors see price signals. Electricity systems which do not pay for themselves are ultimately unsustainable (principles for sustainability given by one party were: integrity, sufficiency and opportunity, equity, efficiency, democracy and civility, precaution and adaptation, and integration.)

In terms of approaches to market reform, OPA was urged to be pragmatic and ensure that its market interventions disrupt price signals as little as possible. However, another party said that while cost reflective prices must be the guiding principle, it is now widely recognized that market interventions (e.g., consumer subsidies or taxes) may be needed to achieve essential electricity system goals.

One party urged for "level playing field" comparisons, with "all in" costs included. For example, gas generation development must take the complete risks of gas supply prices into consideration. Along those lines, many presenters advised that the proper route to go is to determine the complete life-cycle cost for every different fuel. LUEC (Levelized Unit Energy Cost), defined as the entire life-cycle cost of a given technology divided by the energy generated by the technology over its lifetime, was widely discussed as a very valuable costing

methodology. However, OPA was told to consider costs in terms of customer price impacts as well. Strategically factoring in economic and environmental features using a variety of analytical tools was suggested in moving toward optimal pricing.

Social Issues

OPA was reminded numerous times of the social considerations for its planning, including community impacts. For example, OPA heard that "NOPE" (Nothing On Planet Earth) may become a factor in the implementation of OPA's plans.

OPA was asked to address public confidence, to win and sustain public understanding and trust. This depends on energy sector transparency and better public information and education, starting in particular with young people.

The importance of retaining operational, technical and human infrastructure, and how institutions must educate students in this industry and support them entering the profession was highlighted. This was suggested as being essential to combating the belief by some that Ontario's power system is a dying industry.

In summary, these stakeholders recommended incorporating and analyzing a wide variety of options and solutions in OPA's electricity system planning, without promoting any one particular type of planning analysis or tool.

2.3.4.2 Issue Area 2

Advice on appropriate approaches to constructing conservation and demand management (CDM) portfolios for inclusion in long-term plans.

Conservation and Demand Management (CDM) might be considered a "motherhood and apple pie" issue, as not one presenter recommended forgoing its incorporation into OPA's supply mix plans. However, some parties submitted that CDM should be the number one option, possibly providing up to 40%-50% of the long-term solution, while others saw it as a very small potential slice of Ontario's total electricity supply needs.

Cautiousness

OPA was advised that a "negawatt", i.e., the non-consumption of power, is not the same as a megawatt, as the latter provides industry, jobs and ancillary services. In this party's view, providing an incentive for someone not to consume a product is wrong.

Some parties addressed concerns specific to LDCs, regarding the implementation of CDM, including safety, damage to the distribution system, interference of supply to others, and

recovery of direct incremental costs. LDCs have a conflict between the need to recover costs through electricity sales and the need to encourage customers to conserve. If LDC CDM programs are well-designed and have economies of scale, and LDCs can claim the costs and can be protected for loss of revenue, then LDCs will likely be supportive.

It was suggested that there could be merit in such programs designed by the Conservation Bureau as long as LDCs are not left conflicted between Conservation Bureau edicts and OEB approvals.

OPA was asked to ensure that LDCs will continue to have a lead role in the delivery of CDM, despite the fact that ultimately it is up to the OEB to establish the necessary regulatory framework.

OPA was also told that LDCs are fragmented and province-wide applications such as social housing commercial business programs would be advisable. Conversely, it was suggested LDCs need a role in program development. For example, a local area may need some specific tailoring relative to the needs of an entire region.

Presenters also informed OPA about current barriers to successful implementation of CDM. For example, with respect to construction of homes and other buildings, municipalities cannot require standards more stringent than the Ontario Building Code. There was support for practical code changes based on realizable best practices. OPA learned, as well, that some in the power industry find Ministry of Environment regulations unworkable.

Efficiency standards in Ontario are managed by Ministry of Energy, which can pass appliance efficiency standards via regulations in Ontario. However, OPA was advised of the prudence of consulting with the industry before passing such higher standards.

In terms of the capital costs in implementing CDM, OPA heard opinions to the effect that programs designed to influence consumer behaviour are ineffective. Payback periods, which is the time between the capital cost of conservation or efficiency measures and when the measure starts to pay a dividend, have the biggest impact on behaviour. Stakeholders felt that the time to payback for much CDM was too long. As well, lack of accountability is a key barrier to implementation of real conservation measures.

Encouragement

One presenter encouraged conservation as the lynchpin of the supply mix portfolio, indicating strong support for Demand Response programs. OPA was advised that on high peak consumption days we should pay consumers, possibly via aggregators, to reduce demand. The result would be to keep money here in Ontario (money that would have otherwise gone to neighbouring electricity-producing jurisdictions) and it would reduce pollution as well.

In contrast to the cautious comments above, OPA was told that it costs less to pay end users not to consume than to build new supply to meet peak demand. The more pragmatic solution (and the fundamental point) is to work on the demand side and not build generation to meet higher and higher peaks. OPA was warned that conservation programs will not be continued if excess capacity is created by new nuclear.

Three policies areas were proposed which could act against business as usual were recommended. The first was the removal of constraints on cogeneration. The second included the provision of financial incentives for purchasing efficient technologies, and the third was providing innovative financing to reduce payback times on efficient technologies. Again, the largest impact on behaviour was through the provision of innovative financing in order to reduce payback periods.

OPA learned that the bulk of energy efficiency savings is to be found in the commercial and institutional sectors via building shell, HVAC (heating, ventilating and air conditioning) and lighting improvements. Industrials, who are already more efficient than other sectors, find the benefits of installing cogeneration and the resulting increase in their revenues. Certain industries, such as mining, are worse off, but others are net better, such as petrochemicals.

A hospital expansion plan involving improved energy efficiency was related to OPA. In the process of having its expansion plans approved, the hospital was told by government to cut its projected costs. The result was that the hospital eliminated all energy efficiency initiatives. However, had there been a mandatory efficiency standard, then the plans could not have been amended in those energy efficiency areas, and all other new buildings would also be forced to put in higher efficiency features.

As well, mandated targets, such as 10% reduction in energy consumption by a certain date, would force building owners to talk to tenants about implementing energy efficiency initiatives. There is an important role for higher minimum efficiency standards in this industry as well as for household electrical appliances. For example, take non-energy star appliances off the market via setting regulated standards.

Implementing now what can be done quickly was stressed. For example, set standards immediately for energy efficient houses, because those built now will still be around, and providing savings, for many decades. In particular, establish a multi-year funding program providing upfront incentives and zero-interest loans for new energy efficient social housing construction. It was argued that the only sector that will accept the really long-term payback is the public sector and if we implement the long-term payback the province will get 30-40% reductions in consumption.

Some parties advised that LDCs are prime delivery agents for CDM but they are not the only ones. It is difficult for an LDC to be seen as cutting special deals for some parties, and thus, it

was suggested that perhaps the Conservation Bureau could make funds available for special projects and initiatives that are widely applicable.

Specific recommendations to OPA said that the CDM mix should be fairly prescriptive regarding how much is economic. It was suggested that OPA can serve as a CDM information clearinghouse, and it can assist in measurement and verification protocols.
OPA was intrigued by the broad range and sometimes very contrasting opinions on CDM and its potential as a supply option for Ontario's future needs. There is much more to be studied and learned about this potential.

2.3.4.3 Issue Area 3

Advice on assessments of different supply technologies and resources in the Ontario setting, including (but not limited to) natural gas generation, coal gasification, nuclear (new and refurbished), wind, biomass and hydro-electric resources.

Generally, presenters recommended a supply mix solution. Most wanted a balanced supply mix with no single resource dominating. One party told OPA to balance the supply mix between fossil and non-fossil sources, as well as to balance between base-load and flexible peaking supply, and to "avoid a dash for gas". There were a considerable number of presenters who said the supply mix should still have some coal, and that it is a mistake to eliminate such a flexible technology, as one party told OPA.

OPA heard that all resources' contributions should be judged against criteria for sustainability, the "three legged stool": environmental, economic, and social aspects. As well, several parties advised that market structure matters equally with fuel supply mix.

For those who believed that coal should be eliminated from the supply mix, the best options were seen to be a combination of new renewables, high efficiency gas fired plants and conservation.

OPA learned that there is a role for fuel cell technologies in a diversified fuel mix for Ontario, but this would require a collaborative policy in order to implement commercially. This technology can compete with wind today, and with proper policy and direction in Ontario it can be deployed, particularly as support to the grid in urban areas and hospital and other institutional applications.

Natural Gas

Comments regarding natural gas did not run the extreme gamut like they did for certain other fuels. Many believed that natural gas could play an important role, possibly as a transition

resource, and as a flexible fuel allowing plants to be installed fairly quickly and to be located at many different sites.

Many presenters made supportive comments about the high efficiency of natural gas fired cogeneration, also known as combined heat and power, as well as its use for district heating.

One party suggested that no new significant infrastructure is required in Ontario to service the new Clean Energy Supply (CES) contracts under the Ministry of Energy's recent RFP processes, but admitted that it is not clear about infrastructure issues for beyond this tranche of supply. OPA was told that somewhere in the order of 400-500 MMcfd of gas would be needed for electricity generation, and whether it is firm or interruptible will determine how much infrastructure will need to be built.

Some stakeholders explained that gas is a little more reliable in the summer, and that Ontario is fortunate due to the benefit of many pipelines coming into the province, providing flexibility of physical supply.

In contrast, one party advised that there are still problems around gas availability. This person was not convinced that there is a large amount of gas, and believed that there is still some risk with obtaining or depending on a large amount to fuel Ontario's electricity generation.

Some did express concerns with respect to price volatility of the natural gas, but one party claimed that this could be addressed with a political explanation that Ontario cannot be blamed for natural gas pricing.

Coal

Some parties expressed satisfaction at the government's replacement of coal-fired generation. One said it is commendable but that we must not replace Ontario coal generation with imported U.S. coal generation. When they raised the subject of "clean coal", they stated opposition to it because of the continuing carbon dioxide (CO_2) emissions.

Several parties asked OPA to recommend that the government reconsider its coal replacement policy, since coal prices are expected to stay relatively flat while gas prices are expected to go up over time, to higher levels than today.

Coal proponents told us that coal is flexible and cost-effective. One party provided economic analyses comparing a "no coal" case to a "clean coal" case. Notably, the "clean coal" case described is the existing coal plants with best available emissions control technologies (wet lime scrubbers and selective catalytic reduction).

The following points were made:

- The "no coal" case results in an additional $3 billion cost for incremental natural gas infrastructure, avoided in a “clean coal” case;
- Replacing coal with natural gas results in $7.6 billion capital plus $3.4 billion per year in gas fuel;
- Generation cost in the "no coal" case is $11 billion higher than in the "clean coal" case;
- The "no coal" case results in Ontario becoming more dependent on other jurisdictions for electricity;
- For the "clean coal" case, 80% of the emissions reductions would be achievable at 20% of the cost of the “no coal” case; and
- Elimination of SOx, NOx, and metals can be done for only $400 million per year instead of the costs (above) to replace.

Two reasons were provided for suggesting OPA recommend that the coal handling facilities be maintained (i.e., coal infrastructure and hangars, insurance coverage). First, Ontario is better off having the coal facilities available to keep the supply option alive, if necessary, on a fairly quick turnaround. Second, OPA was asked to preserve the capability for the next generation of coal, or preserve it in order to ensure reliability in the short to medium run.

OPA was told that coal plants should be refurbished and then eventually the sites could be used for new build coal plants. Second generation coal plants are easier to support with a clean coal solution for 2015-2020. The potential for carbon dioxide sequestering was mentioned in this longer term context.

Some were critical of government’s desire to eliminate coal but not for the desire to eliminate SOx, NOx, metals, and carbon dioxide. One party said, “don’t rule out coal, rule out emissions”.

Gasification

OPA heard that gasification is the conversion of any carbon based fuel into a synthetic gas or “syngas” ($CO + H_2$), a process also known as “partial oxidation”. Feedstocks include coal, petroleum coke, sludge, oil, biomass, and natural gas. The syngas produced by gasification can be cleaned (removal of sulphur components, mercury, etc.) and then used as a chemical feedstock or as a fuel.

IGCC (Integrated Gasification Combined Cycle) applied to coal as a feedstock is often referred to as “Clean Coal” electricity generation. There is a way to remove carbon dioxide from IGCC but it will cost more in capital and in efficiency. (The estimate is a 10% loss in efficiency by increasing waste heat.) Carbon dioxide removal is not yet proven but is being piloted. The cost of IGCC is projected to be competitive with $6/MMBtu natural gas.

Nuclear

OPA heard extreme views on the issue of nuclear-powered electricity generation. Stakeholders said that informal polling shows a split between opposition and support for new nuclear generation, and this was reflected in the presentations made to OPA.

Opposition to Nuclear

Many parties stressed that Ontario should allow its nuclear facilities to die their natural deaths, due to the historical cost and reliability issues. Some expressed concern over cost and timing uncertainties associated with new nuclear builds, and that critical life-cycle costs (from mine to waste disposal) are not available.

Certain parties noted the unique set of security and safety issues with nuclear plants, which has led them to conclude that nuclear is not a sustainable source and, therefore, that Ontario must move to a fully renewable system.

Some presenters mentioned the need to level the playing field in cost comparisons, as nuclear and fossil fuels have been subsidized for years. These comparisons must include "all in" base-load costs, including consideration of all risks for cost overruns, to be paid by private shareholders, and subject to the same financial penalties as natural gas plants for delays in start up, for example.

OPA was told that in order to have effective planning the decision to close down Ontario's aging nuclear facilities needs to be made, which will result in billions of dollars being saved and possibly re-directed towards other (presumably more palatable) initiatives. This same presenter believed that building transmission lines to carry power from Manitoba is a better choice than re-investing in nuclear.
OPA heard that risk with nuclear plants outweighs the potential risk of burning natural gas. One party firmly believes that costs and problems with nuclear are beyond managerial issues, but more to do with the technology.

Support OF Nuclear

OPA was told that, in polling, where people are concerned about security of electricity supply, they tend to support nuclear generation.

Some proponents of nuclear generation made the case for replacing expiring nuclear plants with new nuclear plants. In order to retain the current level of 40% of the province's supply, 4,000 MW of new nuclear supply would be required on top of refurbishment projects. OPA heard that the province would need to have new nuclear on stream by the time of Bruce B and Darlington refurbishment outages. This refurbishment must be coordinated in order to avoid the creation of another significant supply gap in the next decade.

One party claimed that the tipping point with respect to the economical size of a new nuclear plant is about 650 MW. Anything smaller than this does not make a worthwhile transaction, due to the time required to negotiate, obtain approvals, construct and implement the project.

Most proponents are comfortable building on an existing site. In this context, several presenters expressed belief that the communities of Kincardine, Darlington and possibly others would agree to building a nuclear plant due to it providing high quality jobs. However, the location of a plant must take into consideration market load and transmission requirements, which are generally outside the region where the physical plant is located.

One proponent gave OPA a theoretical new nuclear build timeline: one must commence first stage processes by first quarter 2006 in order to complete negotiations, and put in an order for reactor units by November 2009, for commercial operation by November 2013. Staff could be trained during pre-construction and construction stages (4.5 years) to be able to operate in time for start up. Construction experts can become operational experts, which would build a new generation of nuclear workers, since the average age of today's workers is 49.

Some parties claimed to be technology neutral with respect to the installation of new nuclear reactors, whereas others were fully supportive of the next generation of CANDU, that is, Canadian AECL's ACR technology. OPA was told to expect a major lobbying campaign should new nuclear be considered in the supply mix. With respect to refurbishment, OPA heard that these contracts should be negotiated as far in advance as possible. OPA was warned "don't let negotiations become the critical path".

OPA learned that the industry cannot refurbish more than two plants simultaneously because it is a significant undertaking with respect to personnel, resources, supplies, etc. The biggest danger is to keep delaying refurbishment and then say "hurry up", due to a need to get it done in 18 months, versus 24-30 months that is required to do the job properly and cost effectively. Refurbishment becomes much more expensive if it is forced into a short period of time.

One party claimed that if there was a tie between refurbishment or a new build, they would go to a new build option.

Generation from Renewable Sources of Energy

Not unlike the issue of Conservation and Demand Management, no presenters to OPA's stakeholder sessions opposed the inclusion of renewable energy sources as part of Ontario's electricity supply mix. There were significant variations, however, in the amount or percentage of the total portfolio being recommended.

Presenters acknowledged that most renewables are intermittent, thus one should measure the amount of power produced over time, as opposed to the instantaneous maximum output. "Look at megawatt-hours and not just megawatts" one party told OPA.

Another party asked OPA to set a long-term goal of a 100% renewable system with an interim goal of 60% renewables by 2020.

OPA was reminded of the need to attract early adopters who are willing to pay a premium for the inclusion of renewable energy in the supply mix, as long as they get the message that this is the right thing to do. However, one party's research indicated that renewables are becoming cost competitive at a faster rate than had ever been anticipated.

OPA learned that it could resolve most related transmission and distribution issues if it could convince the OEB to approve pooled connection costs for up to 40 km, such that the LDC would receive contributed capital from OPA.

In terms of training and expertise in renewable energies, OPA heard that no university in Canada offers undergraduate, Masters or PhD degrees in renewables. This creates a bottleneck for this sector, as universities do not have the capability to teach and train the needed change for society to embrace these forms of electricity generation.

Standard Offer Contracts (SOC)

As described previously, SOCs are agreements between the system buyer of electricity and producers of relatively small amounts of renewable generation.

Many parties within the renewables field expressed strong support for the implementation of an SOC. When asked specifically if wind projects should have a standard offer, proponents said "yes", as currently they would not research many potential sites if they did not believe they could enter into a SOC with OPA.
It was recommended that to simplify SOCs, consideration should also be given to standardized connection costs, thus ignoring differences in these costs across different projects.

Hydroelectricity

OPA was told that 60% of current hydroelectricity sites are located in southern Ontario, with new potential existing in other areas, which would result in a need for transmission. It is possible to derive incremental capacity and energy via upgrade programs to existing hydroelectric plants, but it would result in mostly additional energy and little capacity.

OPA learned that there is a potential for up to 2,000 MW at greenfield sites in Ontario, mostly via flooding, which causes issues for First Nations located in these regions. OPA was advised that there is a need for flexibility in these processes, as it could take as many as 10 years in negotiations with First Nations. A representative of First Nations communicates told OPA that it is important to involve First nations at the outset of such plans, rather than initiating negotiations after plans have been made.

One party provided the following potential for the regions north of the 50th parallel, for a total of over 500 MW capacity:

- Small size (1 MW+) hydroelectric: 175 sites
- Large size (5 MW+) hydroelectric: 55 sites

There was lament that provincial parks have been created by the Ministry of Natural Resources without consulting with the communities in the area. This includes the "Lands for Life" process whereby 8% of the provincial land mass is preserved as parks. These park boundaries entangle potential sites from development. OPA was informed that any potential development north of the 50th parallel is a "direct award" to the communities for development, whereas south of that point requires a competitive tendering process. Parties are concerned about legislation that constrains hydroelectric development opportunities, as policies are moving to create water parks on which hydroelectric facilities currently exist. There was a concern that not all the right parties are being consulted on the impact of these policies on electricity needs of the communities.

Pumped Storage Generation

OPA learned more about pumped storage generation. Conventional hydroelectric plants store and release energy as needed, by filling reservoirs during times of lower demand, for use in generating hydroelectricity later, during periods of higher demand. What pumped storage does is pump downstream water back up into the reservoir, by using excess supply that may be available at night. Pumped storage makes more capacity available for use during periods of high system demand.

Ontario has many suitable locations, for upper reservoirs at rivers and lake shores. As well, underground pumped storage, using flooded mine shafts or other (vertical) cavities are feasible.

Pumped storage is used in conjunction with wind in Denmark, Germany and Finland; overall efficiency is 70-85% range in the world. However, pricing strategies need to address very high tariffs in the early years, but recognize good profits in later years.

Wind

OPA was advised that the issue for wind is not whether Ontario has the resource, rather it is whether we can connect the resource. Wind potential is geographically dispersed (which reduces variability) and is located close to all load centres. It is close to transmission lines in southern Ontario, but less so in northern Ontario.

Proponent-led, rate-base supported, transmission upgrades can provide more flexibility in the short-term. There is no current policy to address the future transmission needs to match wind turbine planning. Some parties expressed a desire for some sort of hybrid arrangement, one that

would be a compromise between a proponent having to pay the full cost of a transmission line, and pooled cost paid by all users.

Some stakeholders related the issue of adding wind power supply to areas already having adequate supply. There would be a requirement to move the power to some other region. Overloading existing distribution and transmission systems might become a problem as the amount of wind power increases. Initial increments are not a problem but as the province's supply grows to 5,000 MW it will become an issue. One party said that there is a saturation point; Germany may not install any more wind power on land, but will instead install offshore.

Wind proponents asked OPA to ensure financial, fiscal and energy market structures do not create barriers, and ensure that all required provincial and municipal approvals are streamlined.

Parties advised that there is great symmetry between wind and large hydroelectric reservoirs. Quebec is successfully exploiting these types of opportunities by "holding back" James Bay when wind generators run.

OPA heard that, generally speaking, wind power production has worked very well in terms of stimulating or kick starting the renewables industry. Its program design has merits, as it allows jurisdictions the flexibility to come in as they see fit with renewable portfolio standards, RFPs and SOCs, (feed-in tariffs). There has been considerable political support for wind and recent budgets in Canada have reflected this.

Solar

Proponents of solar electricity explained to OPA that the first solar markets in any jurisdiction are residential, which is then followed by the commercial and industrial sectors. Prices have been dropping dramatically and a two-fold reduction is expected by 2010 from 2000, for the whole module cost. (This does not include wiring, insulators and installation.)

In one study on the value of solar electric power, it was determined that the coincidence of peak demand and peak price periods means that solar electricity is more valuable than the average kWh produced by the system.

Stakeholders knowledgeable about solar markets explained that in Ontario there is 3,000 MW of solar potential for residential market alone. By 2025, parties have forecasted 7,100 MW of solar potential for 2.5 million homes. A target was given of 1,200 MW in 400,000 PV (photovoltaic) powered homes by 2025.

Parties recommended that smart meters be integrated with net metering to permit these systems. This requires a small chip to be added, although these proponents do not know whether this will be a specification for Ontario's smart meters.

OPA was also reminded that LDCs need to be paid or kept whole in the loss of load when these types of renewable systems are installed.

One party proposed a feed-in tariff of $0.42/kWh (which captures approximately 40% of system costs), PV program length of 10 years, and an SOC term of 10 years. If spread over the entire provincial ratepayer base this amounts to $0.70/year for an average household (25 kWh/day). A 10 year program was forecasted to result in 15,000 systems or 40 MW installed capacity by 2015.

When asked about any opportunity to develop a solar farm or factory, one party explained that the system does develop that way in Germany and Japan. A PV power plant of 1 MW can be built in less than 6 months. While there is some economies of scale when installing a large number of systems, these economies are limited when systems are still modular.

Solar Hot Water

Specific information was presented to OPA on solar thermal, indicating that it could make a big difference by displacing natural-gas-fired and electric hot water. Solar thermal is one of the fastest growing industries in the world. A typical life span for these systems is 25 years, although most manufacturers will guarantee only 10 years.

The following financing concepts were presented on solar: spread the cost over an extended period, and implement a "green mortgage", whereby monthly payments are less than the monthly savings. This results in an immediate payback, but there is no mechanism yet available in Canada for small generators (homeowners, etc.) to obtain the same financing rates as large central power plants. Apparently, too many people are waiting for the government to provide a subsidy or a tax break. When asked whether the province could alternatively simplify all the costs of metering, billing, agents and roll it into one up front cost (as opposed to amortizing them over a period of time), the response was that it could be done, but continuous payment is an incentive to keep the system operating and maintained.

Transmission Issues

OPA was told that the province's transmission grid should be treated as an essential public infrastructure. Reliability is a greater function of the frequency of outages on the transmission wires, therefore new or additional generation is not necessarily the way to reduce outages. Many parties advised that grid investment should lead supply mix; good reliable transmission networks should drive power supply decisions.

Stakeholders realize that no value exists in creating supply mix diversity and then being unable to use that diversity due to congestion. Certain supply mix decisions have transmission implications, which need to be fully reflected. When looking at total economics, OPA was told to be sure to look at the transmission cost element.

Several parties told OPA to tackle transmission constraints, which will mean tackling interveners head on. For example, it was suggested that while some communities would support the construction of new plants on their sites, transmission network approvals would be difficult.

Several parties claimed that different parts of the province and different customers at different points on the transmission or distribution system will have different reliability experiences. One size does not fit all.

Finally, OPA was told that if capacity from tie-lines (interconnections) is needed, build a tie-line, and do not just sign a contract. Relying on tie-lines for long-term firm capacity, that is, greater than 18 months, was considered a mistake.

2.3.4.4 Issue Area 4

Advice on appropriate methods to assess the impact on the natural environment of supply options.

OPA was advised Ontario is still trying to operate in the context of cost assessments only, and that the province must take on targets for climate change as the broader context.

Several parties told OPA about the need for comprehensive Environmental Assessments (EAs) when developing "greenfield" sites. These EAs should be more far reaching than an EA for a refurbishment project.

OPA was asked to target emission-free energy and to consider environmental externalities when assessing supply mix options. However, others commented on the need to wrestle with environmental compliance. They agreed that proponents must meet the laws, but if OPA were to recommend a higher standard then it would in effect usurp the government's role. OPA was warned to be careful in imposing this kind of view. This was not to say that higher standards cannot be considered. Rather, parties asked OPA not to change the rules of the game as set by government.

OPA was advised of appropriate methods to assess the impact on the natural environment of supply options, including a comparison of energy systems using life-cycle assessment. OPA heard that people need to know that Ontario is doing this (because of climate change, not because of the cost of electricity).

One party claimed that the premiums associated with environmentally beneficial supply sources should be paid by all ratepayers. OPA was told that the key environmental challenges include: biodiversity, ecological sustainability, ecological integrity and environmentally

sustainable economic development. A balance between land-use planning and resource development is required.

OPA was reminded of the desire to legislate policy to protect parks and waterways, and to expand ecological integrity into lands radiating from waterways, even further isolating lands around existing hydro facilities as protected areas.

2.3.4.5 Conclusion

OPA's request for input from such a disparate group of stakeholders yielded detailed and, for the most part, pragmatic but ambitious recommendations. Some common themes emerged and some major areas of disagreement were highlighted. However, consistent in almost every presentation was the expressed desire for supply mix diversity, for conservation and demand management, and for the inclusion of renewable sources of electricity. There were adamantly opposing views regarding both coal and nuclear powered generation, while natural gas did not elicit views as polarized as those supply sources. Other generation technologies were supported or opposed to an even lesser extent. Finally, OPA was cautioned to be business-like about the supply mix advice, otherwise Ontarians will get something they don't want, "a pig in a poke".

2.3.5 In-Depth Interviews and Public Opinion Polling

For the third component of its stakeholder consultation process, OPA contracted with Decision Partners Inc. to undertake in-depth interviews and conduct public opinion polling research. Interviews were conducted with 27 industry stakeholders and 35 non-industry societal influencers and public opinion polling assessed the views of 800 Ontarians. The results provided OPA with an assessment of people's beliefs and preferences in relations to electricity supply and issues, and differentials in views between stakeholders and non-industry societal influences and the public at large. The following sections present the results of the interviews and polling, as reported by Decision Partners Inc.

2.3.5.1 Introduction to the Stakeholder Consultation Process

OPA recognizes that effective stakeholder consultation is critical to its ability to achieve its long term planning mission. Such consultation helps focus knowledge and diverse perspectives in ways that can build an in-depth, shared understanding of electricity related topics important to the Government of Ontario and Ontarians.

OPA asked Decision Partners (DP) to develop and manage an effective, inclusive stakeholder consultation process as a key element in the preparation of Advice to the Minister on the appropriate supply mix to meet anticipated demand in the Province. The purpose of the

consultation process was to help OPA professionals better understand stakeholder interests and priorities with respect to various aspects of the supply mix challenge. In-depth understanding of the range of issues and underlying rationale of stakeholder and public judgment of the future supply mix for Ontario along with the degree to which stakeholders and others felt they had an opportunity to participate in the process in a meaningful way was critical to OPA.

Stakeholder Consultation Purpose

The primary purpose of the process was to identify stakeholder interests and priorities regarding the future energy mix for Ontario, including the risks, benefits, and tradeoffs of each of the fuel source options. Stakeholder judgment criteria were integrated with the technical assessments and modeling undertaken by other members of the OPA team.

Overview of the Approach

Dialogue-based approaches involving diverse groups of citizens and stakeholders have become the standard for addressing important policy issues in Canada and elsewhere, replacing the mere provision of "expert" information. The most successful approaches combine sound science and systematic uncertainty analysis with participatory deliberation by an appropriate representation of affected parties, policy makers and specialized or focused interests.

Decision Partners used its science-based, expert model/mental models-based approach[1] that has proven instrumental to the success of a broad range of public and private clients in Canada, the United States, and internationally who are faced with similar complex challenges.

The selection of research methods must be suited to the research task. For this initiative, the task was to discover and characterize in-depth people's thinking about an appropriate 15 to 20 year supply mix for Ontario, extending to 2015 – 2020.

Decision Partners conducted mental models research with key stakeholders, which is qualitative in nature, and used the research results to design an Internet-based poll capable of generating quantitative information about, as well as additional insights into, Ontarians' perspectives on the supply mix challenge. Polling and group methods (such as focus groups) alone, or in combination, were deemed to be unsuitable for the task due to important limitations in both methods.

The mental models research method involves in-depth, one-on-one interviews. The one-on-one situation helps to approximate the decision-making environment within which most people form their attitudes about a topic. The method allows free expression and encourages

[1] The use of mental modeling and confirmatory large-scale population surveys is covered in depth in *Risk Communication: A Mental Models Approach*, by M. Granger Morgan, Baruch Fischhoff, Ann Bostrom, and Cynthia J. Atman, published by Cambridge University Press, 2002.

elaboration on topics in order to reveal individual perspectives in considerable depth. Interviewees can readily raise topics that most interest them, but which may be outside of specific questions. Because a full set of beliefs is elicited from each interviewee, structured analyses are possible. Analysts can identify what people believe and why they believe it.

In keeping with the mental models research method, Decision Partners first prepared an expert model summarizing expert knowledge of influences on the quality of supply mix advice to the Minister and influences on stakeholder judgments of the supply mix advice. The expert model served as the basis for design of the stakeholder and web survey protocols, and as the analytical framework for both.

The stakeholder consultation process comprised six elements, summarized below:

Develop OPA Stakeholder Consultation Guiding Principles: The first step in the process was to work with the OPA team to determine their values and priorities for stakeholder consultation. Following several discussions, the following principles were developed to guide the stakeholder consultation process for the supply mix and future OPA initiatives.

Stakeholder Consultation Purpose: The purpose of stakeholder consultation is to further the mission of OPA by helping focus knowledge and diverse perspectives in ways that can build an in-depth, shared understanding of electricity related topics important to the Government of Ontario and Ontarians. Information and advice received through stakeholder consultation is considered by OPA to be critical to the Authority's ability to provide well-informed recommendations to the Minister of Energy.

The insight OPA gains through consultation with a range of stakeholders and the resulting advice to the Minister must effectively balance the needs, interests, and priorities of Ontarians, whether they are commercial, industrial, institutional, or residential electricity users.

Purpose of the Guiding Principles: The stakeholder consultation guiding principles have been developed to guide the design and implementation of OPA's stakeholder consultation processes and key activities. They also serve as guides for the conduct of OPA sponsors of consultation processes and the key participants in them.

Guiding Principles: OPA's stakeholder consultation efforts are focused on gaining insight and input required to inform mid- to long-term energy-related decisions. Consultation efforts are:

- Advisory in nature.
- Transparent.
- Inclusive.
- Stakeholders and all others are treated with respect and relevance.
- OPA offers multiple communication channels to enable stakeholder dialogue and input.

- Our stakeholder consultation processes call for clear, measurable objectives and evaluation of both the process and the outcomes.

Develop the Expert Model: The mental models research method calls for first integrating the knowledge of experts on the topic(s) at hand into a tractable form. For this purpose, Decision Partners prepared an expert model based on input from in-depth interviews with experts within OPA.

The resulting expert model is an influence diagram that captures and synthesizes expert knowledge of influences on the quality of supply mix advice to the Minister and influences on stakeholder judgments of the supply mix advice. While providing a valuable summary of expert knowledge, it also provides the analytical framework for the mental models and web survey research conducted for this initiative. It was used to design protocols for the mental model interviews and the web survey.

Conduct Mental Models Research: DP conducted 62 confidential, one-on-one interviews by telephone with 27 Industry stakeholders and 35 Non-industry stakeholders based on a sample of approximately 200 provided by OPA. This sample size is typical of that used in the qualitative mental models research method recommended by Decision Partners.

The purpose of the interviews was to discover the primary influences on stakeholder judgment of Ontario's need for electricity and their idea of an appropriate balance of supply mix elements – namely, conservation and demand management (CDM), renewable sources, and advanced conventional sources.

Interviewees were asked to respond to a series of questions that were designed to allow for free expression, followed by specific ratings questions. In order to reveal in-depth, individual perspectives, Interviewees were encouraged to raise additional topics spontaneously and to elaborate on their thoughts. Interviews were tape recorded (with permission) to enable subsequent analysis as required.

The design of the protocol enabled Decision Partners' researchers to capture the detailed thoughts of the interviewees, then assess varying sets of beliefs and judgments about elements of the supply mix portfolio. By following this research with the Ontario-wide web survey, it was possible to understand and quantify how broadly these perspectives were shared by people across the province.

Conduct Parallel Web Survey: The results of the mental models research were then compared with results of a parallel web survey of 879 individuals developed by Decision Partners and administered by Decima Research. Web Survey Respondents comprised a representative sample of Ontario's general population.

The web survey included closed- and open-ended questions, and the interview protocol involved open-ended questions followed by rating questions. This complementary protocol design enabled Decision Partners to analyze the results of the web survey and the mental models interviews against the same set of parameters.

Conduct Stakeholder Workshop: Decision Partners designed and facilitated a workshop with stakeholders who had participated in the mental models portion of the consultation process. The purpose of the workshop, held November 3, 2005, was to share information and enable electricity Industry and Non-industry stakeholder engage in dialogue on values, tradeoffs and tough choices on key challenges related to the development of an appropriate supply mix. This additional insight was used as OPA prepared its advice to the Minister.

Report on Consultation Findings: This report identifies influences on Industry stakeholders, Non-industry stakeholders and Ontarians' judgments of key issues related to the need for electricity, the most important impacts to consider, and a balanced supply mix portfolio. It discusses key findings from the consultation process, which was used by OPA to inform its advice to the Minister on supply mix options.

The consultation process includes the formal research conducted by Decision Partners: mental models research, web survey of a representative Ontario public and the stakeholder workshop. Other consultation channels – such as meetings, technical briefings with industry experts, position papers, etc. – were also used by OPA to generate input into the supply mix advice and are reported elsewhere in the OPA report.

Notes on the Research Component of the Report

The research segment compares findings and highlights important gaps and alignments between the various groups consulted: Industry stakeholders, Non-industry stakeholders, and web Survey Respondents (the Ontario Public). To aid the reader, mental models research and web survey research highlights are reported together.

Findings from the research are analyzed and reported against the expert models. For the purposes of this report, the mental models research instrument is referred to as the "mental models interview" or "interview." The web survey research instrument is referred to as the "web survey" or "survey." The aggregate mental models research sample is referred to as Interviewees, indicating all 62 Interviewees unless otherwise specified. The terms Industry and Non-industry refer to the 27 Industry stakeholders and 35 Non-industry stakeholders respectively; while the terms Respondents and Survey Respondents refer to the web-based survey sample of 879 Ontarians unless otherwise specified. Differences among these groups are noted where significant. Note that, when used, the terms "the majority" refers to > 80% of Interviewees or Respondents; "most" refers to 60-80% of Interviewees or Respondents; "many" is 40-60%, "some" is 20-40%, and "(a) few" is < 20%.

2.3.5.2 Mental Models and Web Survey Research

Mental Models Research Method

Research Sample: A "mental models" approach was used by Decision Partners to design conversational protocols for interviews with 62 stakeholders in two groups: 27 Industry and 35 Non-industry stakeholders. The research sample was provided by OPA. The Industry group included representatives of organizations such as utility companies, industry associations, electricity consultants, and labour associations. The Non-industry group included representatives of organizations such as municipalities, environmental non-government organizations, large electricity users, and individuals.

Pre-arranged interviews were conducted between September 15 and October 12, 2005. They ranged in duration from 20 to 105 minutes, with an average of 50 minutes.

Research Topics: Interviewees were offered an agenda of topics to discuss in a way that allowed for free expression. They were encouraged to raise spontaneously any additional topics and to elaborate on their perspectives on these topics.

The mental models protocol (or questionnaire) focused on the following topics:

- Influences on the Need for Electricity in Ontario
- Balance of Supply Mix Portfolio
- Influences on the Quality of Supply Mix Analysis
- Stakeholders' Advice to OPA

Other topics spontaneously mentioned included the following:

- The urgent societal need for electricity, including the impacts of the August 2003 blackout;
- Environmental policies, including issues related to the Federal Government's Kyoto commitments and the Ontario Government's coal phase-out policy;
- Timeframe considerations, including the immediate electricity needs, impacts of our choices on future generations, and the need to look beyond 15-20 years when it comes to electricity systems planning;
- The need for expert input – public input and stakeholder engagement into the supply mix advice in particular and the energy policy in general;
- Issues related to OPA and government leadership.

Web Survey Research Method

A parallel web survey of a representative sample of Ontarians was conducted based on the mental models research. The survey protocol designed by Decision Partners was based on key

questions in the mental models interviews. Decima oversaw the data collection process; Decision Partners analyzed and reported the results.

The web survey of Ontario residents was conducted between October 3 and October 6, 2005. A total of 879 surveys were completed (target was 800). 53% of the respondents were male, while 47% were female. Respondents were asked about their familiarity with electricity issues in Ontario: 12% reported being very familiar, 68% were somewhat familiar, 18% were not very familiar, and 2% were not at all familiar. All data were also cross-tabulated to account for variations in Respondents' demographics and their judgments. Decision Partners analyzed the web survey results and compared them to the results of the mental models interviews for inclusion in this report. The margin of error on survey responses is +/-3.3%, meaning that the true response is within 3.3 percentage points of the reported survey response 95% of the time.

The web survey protocol focused on the following topics:

- Influences on the Need for Electricity in Ontario
- Balance of Supply Mix Elements
- Ontarians' Advice to OPA
- Trusted Information Sources about Electricity Issues in Ontario

2.3.5.3 Overall Research Findings

The mental model and web survey research demonstrated clear priorities on the part of stakeholders and diversity in their beliefs about the importance of the supply mix elements, conservation and demand management, renewables, and advanced conventional sources. Top line findings are summarized in the box which follows.

Top-Line Research Findings

Priorities Regarding the Need for Electricity

- In general and on average, Industry and Non-industry stakeholders' judgments were very similar.
- The values and priorities underlying Interviewees' perceptions of the need for electricity in Ontario that influence their considerations on supply mix were remarkably consistent.
    - Availability and reliability were the primary influences on the need for electricity, ranked high by over 90% of all of the Industry and Non-industry Interviewees.
    - Environmental responsibility was next in terms of rated questions. It was rated high or medium by almost all of the Interviewees.
        - Several talked about health impacts of power generation when they discussed environmental responsibility.
    - But throughout the interview, Interviewees spoke more about availability of electricity and the economic impacts than they did environmental impacts – emphasizing that availability is "critical" and must be the priority.
- For the most part, Survey Respondents' judgments were similar:
    - When combined, availability and reliability of electricity were rated the most important factor by 52% of Respondents.
    - 17% of Respondents rated environmental responsibility as the most important factor.

Considerations on the Supply Mix Portfolio

- There is no one right portfolio:
    - The majority of Interviewees acknowledged the challenge of defining the ideal or even an optimal supply mix portfolio. As one noted, "there is no silver bullet." There is not one dominant portfolio among those proposed.
    - Survey Respondents did not have one preferred supply mix portfolio, nor was there a clear set of portfolio scenarios.
- A wide range of portfolios were offered. In general:
    - Industry Interviewees tended to favour conventional/advanced conventional sources more than Non-industry Interviewees.
    - Non-industry Interviewees tended to favour a more balanced portfolio, though many Interviewees in both cohorts talked about the importance of "a balanced portfolio."
    - Survey Respondents favoured more renewables.
- In aggregate, Interviewees and Survey Respondents allocated about 20% to CDM, 30% to Renewables and 50% to Conventional or Advanced Conventional Technologies.

Considerations on Sources

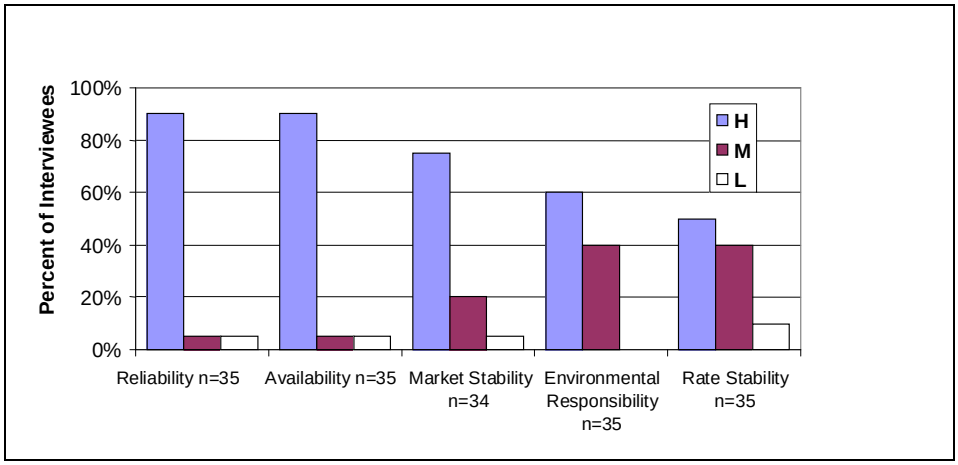
- Interviewees and Survey Respondents included a significant amount of wind in the Renewables portion of their portfolios; Survey Respondents and Non-Industry interviewees also favoured solar. Biomass was included in fairly significant amounts by Industry and Survey Respondents.
- Interviewees emphasized that the portfolio must be diverse in terms of cost of the various components (capital cost, fuel cost, maintenance cost), generation size and type, and environmental impact.
    - 55% Industry and 35% Non-industry believed it should include "clean coal"; 10% Industry and 25% Non-industry said it should not include coal.
    - 85% Industry and 50% Non-industry believed that nuclear should be part of the supply mix; 10% Industry and 15% Non-industry said it should not.
- Survey Respondents similarly emphasized diversity, but put greater emphasis on large-scale hydro, distributed generation and natural gas than the Interviewees.
    - 75% said the portfolio should include nuclear; 15% said it should not.
    - 70% said it should include coal; 18% said it should no.

Influences on the Need for Electricity in Ontario: Priorities underlying Interviewees' thoughts on design of the supply mix portfolio were clear and consistent: availability and reliability were the primary influences on the need for electricity, ranked high by over 90% of all of the Industry and Non-industry Interviewees. Environmental responsibility was next in terms of rated questions. It was rated high or medium by almost all of the Interviewees. But throughout the interview, Interviewees spoke more about availability of electricity and the economic impacts than they did environmental impacts – emphasizing that availability is "critical" and must be the priority.

While most Interviewees rated most influences high, there were some exceptions:

- Many said that rate stability was of medium or low importance because Ontarians should "experience the true price of electricity."
- Many distinguished between rate stability (price volatility) and price.
- A few (10% Non-industry) rated environmental impacts as highest in importance, noting the long-term impact of Ontarians' reliance on conventional sources.
- A few stated that availability and reliability were of medium or low importance, suggesting that Ontarians' were over-reliant on electricity.
- Most Interviewees acknowledged that tradeoffs were necessary because efforts to improve one factor often come at the expense of another.
-

Figure 2.3.1 – Non-Industry Response to Drivers - Prompted



Decision Partners Inc., 2005

Survey Respondents were asked to rate the importance of a series of factors related to electricity. For the most part, Survey Respondents' judgments were similar to those of the Interviewees. Each factor was rated of high importance by over 50% of Survey Respondents. Availability and reliability of electricity was rated the most important factor by 52% of Respondents. 17% of Respondents rated environmental responsibility as the most important factor. The graph below summarizes these results.

Table 2.3.3 – Percent of Survey Respondents Rating Most Important Factor

Availability	28
Reliability	24
Stable Rates	23
Environmental Responsibility	17
Market Stability	8

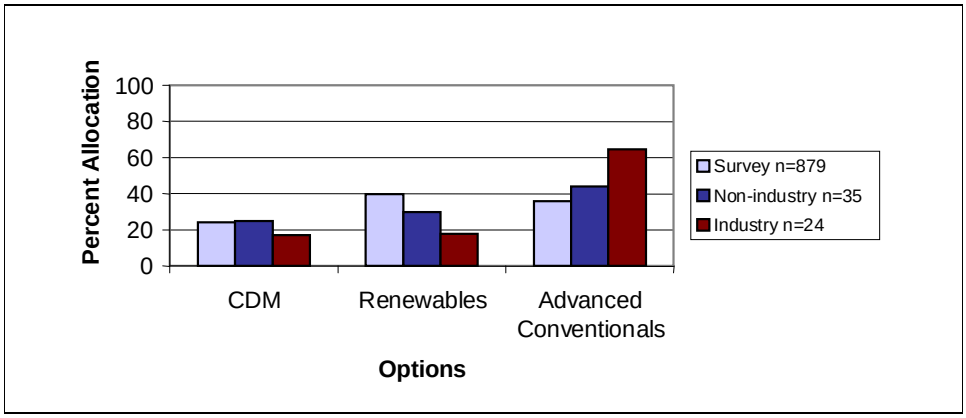
Source: Decision Partners Inc.

Ontario Balance of Supply Mix Elements: Interviewees were asked to suggest a supply mix portfolio by assigning percentages to each of three categories: conservation and demand management (CDM), renewable energy sources, and conventional and advanced technology conventional sources.

The majority of Interviewees acknowledged the challenge of defining the ideal or even an optimal supply mix portfolio. As one noted, "there is no silver bullet." Overall, both Industry and Non-industry portfolios ranged across the entire spectrum of possibilities. No single portfolio assignment emerged as the right one, nor was any portfolio dominant over the others. Industry Interviewees, however, tended to place greater emphasis on Conventional sources (65% on average) with support for CDM and Renewables being evenly split. Non-industry Interviewees tended to favour a more balanced portfolio, though many Interviewees in both groups talked about the importance of "a balanced portfolio." It is important to note that, by "balanced," they did not mean an even distribution, or one-third, one-third, one-third. Rather, they meant good proportional relationships among the three components: in aggregate, about 20% CDM, 30% renewables, and 50% advanced conventional.

Survey Respondents were also asked to suggest a supply mix portfolio by assigning percentages to each of three categories. Similar to findings in the mental models research, portfolio allocations varied widely across the entire range of possible portfolio allocations. On average, Survey Respondents allocated an amount for CDM similar to that of the Non-Industry Interviewees (24%). On average, Survey Respondents were more optimistic in their allocations of renewables (40%) and reacted less favourably to advanced conventional sources (34%) than both Industry and Non-industry interviewees. But it is worth noting that Respondents who rated environmental responsibility as the most important factor allocated significantly more of their portfolio to renewables and significantly less of their portfolio to advanced conventionals than those who rated availability as the most important.

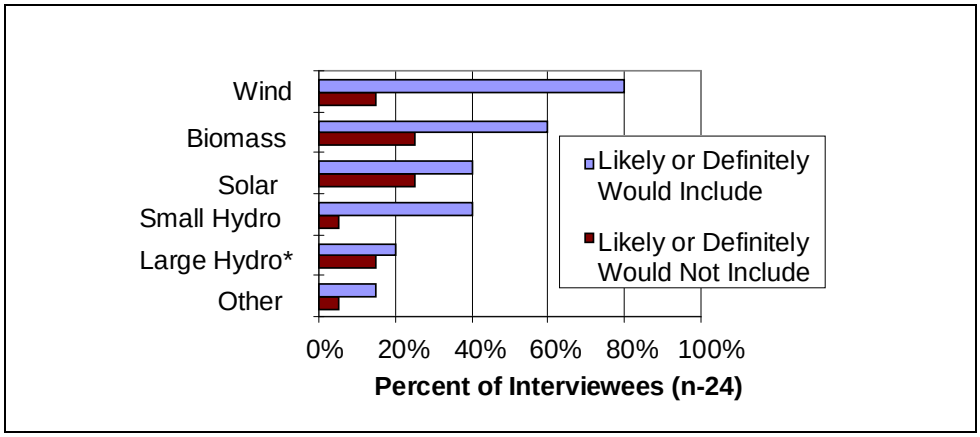
Figure 2.3.2 – Aggregate Portfolio Allocations



Decision Partners Inc., 2005.

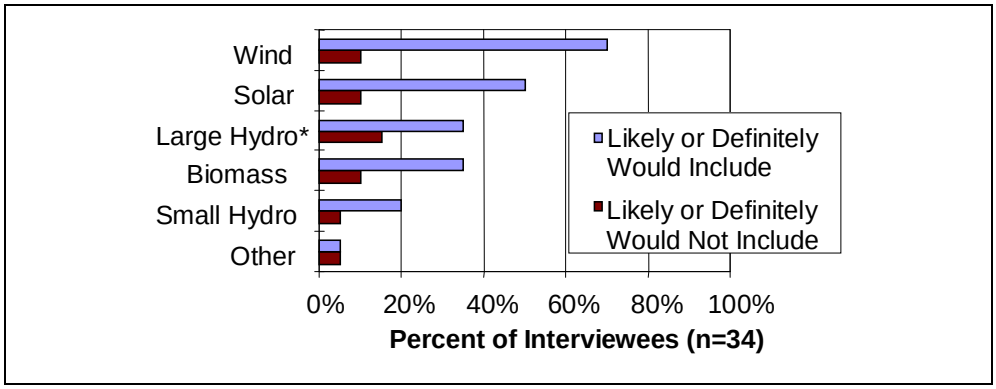
Interviewees and Survey Respondents were also asked to determine whether they would include specific renewable sources in their supply mix portfolio. As illustrated by the graphs below, wind stood out as the clear winner for both groups. Judgments were mixed about solar, small hydro-electric, and biomass. Although not included in the specified definition for renewables, many interviewees spontaneously included large hydroelectric operations as renewable sources.

Figure 2.3.3 – Industry Response to Renewable Sources



Decision Partners Inc., 2005.

Figure 2.3.4 – Non-Industry Response to Renewable Sources



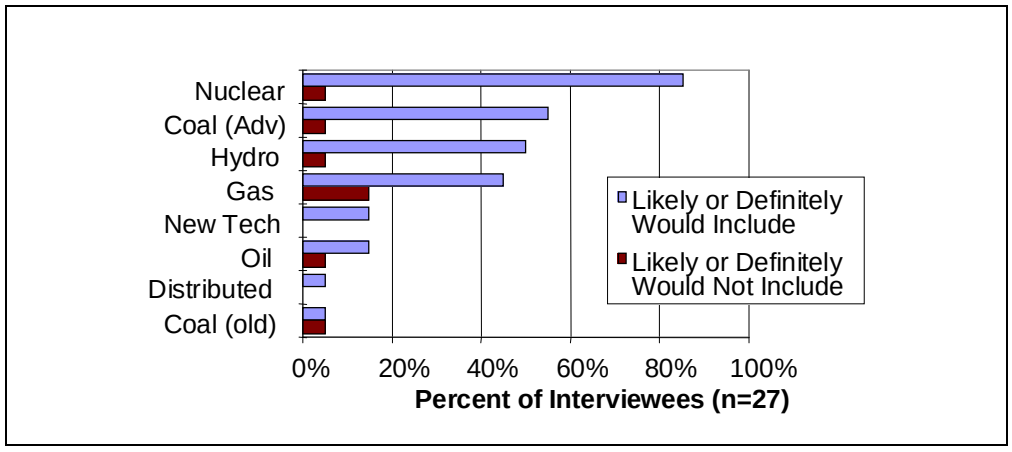
Decision Partners Inc., 2005.

Among conventional sources, nuclear stood out as the most favourable source by both Industry and Non-industry groups. Advanced conventional coal and large hydro projects were also rated favourably. Oil and gas were seen to be less favourable due to issues of cost and availability. Interviewees emphasized that the portfolio must be diverse in terms of cost of the various components (capital cost, fuel cost, maintenance cost), generation size and type, and environmental impact.

Coal, about which Interviewees were not specifically asked, played a major role in many portfolios, as did nuclear:

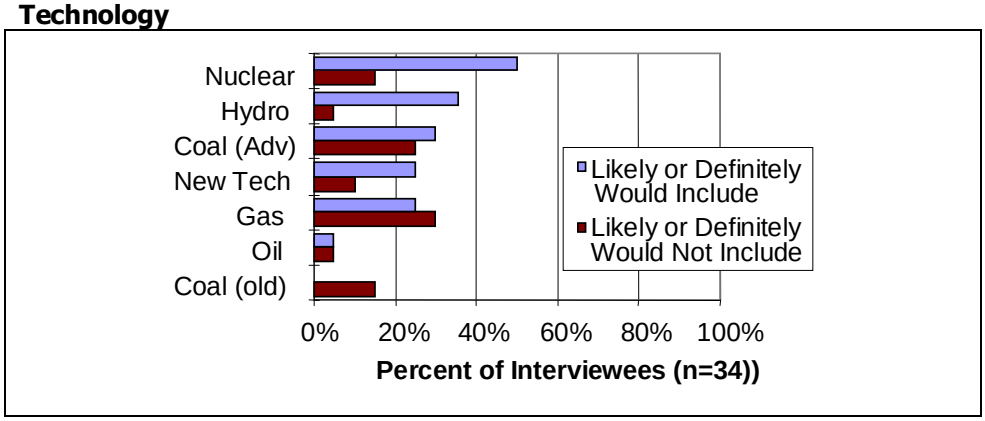
- 55% Industry and 35% Non-industry believed the supply mix should include "clean coal."
- 10% Industry and 25% Non-industry said it should not include coal.
- 85% Industry and 50% Non-industry believed that nuclear should be part of the supply mix.
- 10% Industry and 15% Non-industry said it should not.

Figure 2.3.5 – Industry Response to (Advanced) Conventional Technology



Decision Partners Inc., 2005.

Figure 2.3.6 – Non-Industry Response to (Advanced) Conventional Technology

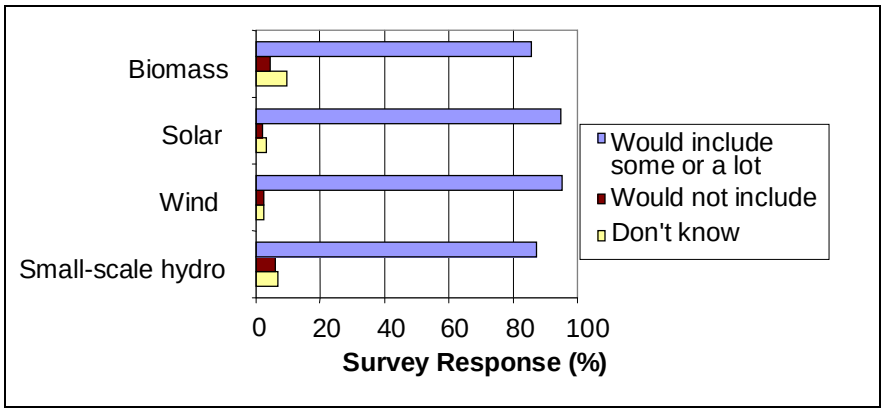


Decision Partners Inc., 2005.

Interviewees were then asked to discuss the strengths and drawbacks of their portfolios. The most common benefit cited by both Industry and Non-industry Interviewees was the prospect of ensuring an available, reliable or sustainable supply of electricity. Environmental benefits were also frequently mentioned. The most commonly cited drawback mentioned was the difficulty of implementing the proposed portfolio. This drawback was commonly cited by Interviewees who had allocated a significant proportion of their portfolio to CDM.

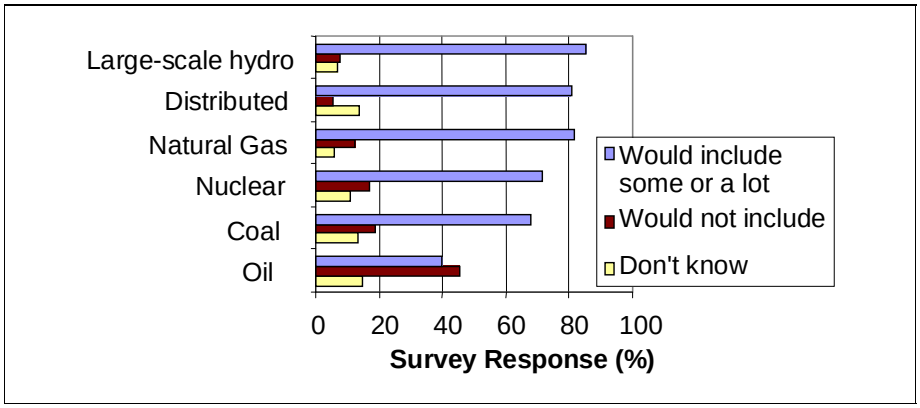
Survey Respondents were also presented with a series of specific renewable and advanced conventional supply mix options and asked whether they would include these sources in their supply mix portfolios. The majority of respondents would include at least some of every renewable source. Except for oil, Respondents responded favorably to each of the advanced conventional sources, with large scale hydro the most favoured.

Figure 2.3.7 – Survey Response to Renewable Sources



Decision Partners Inc., 2005.

Figure 2.3.8 – Survey Response to Advanced Conventional Sources

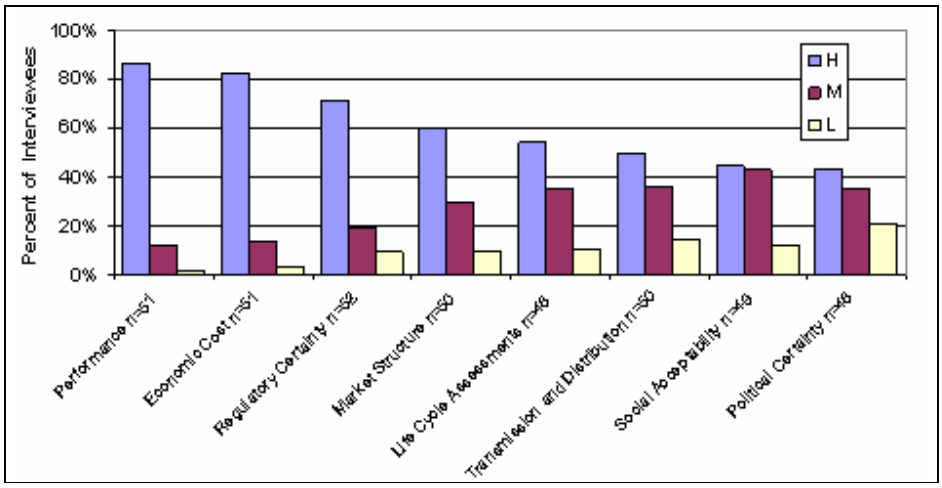


Decision Partners Inc., 2005.

Influences on Supply Mix Elements

Interviewees were asked to rate the importance of the following impacts to OPA's supply mix assessment: performance, economic cost, market structure, impacts of transmission and distribution, regulatory certainty, political certainty, life-cycle assessments, and social acceptability. Again, Industry and Non-industry responses were very similar. On average, all Interviewees rated performance (capacity and efficiency of electricity generation), followed by cost (of producing and distributing electricity) and regulatory certainty as the most important impacts to consider. On average, Interviewees rated social acceptability as a less important factor. The following chart summarizes the aggregate (Industry and Non-industry) response to these questions:

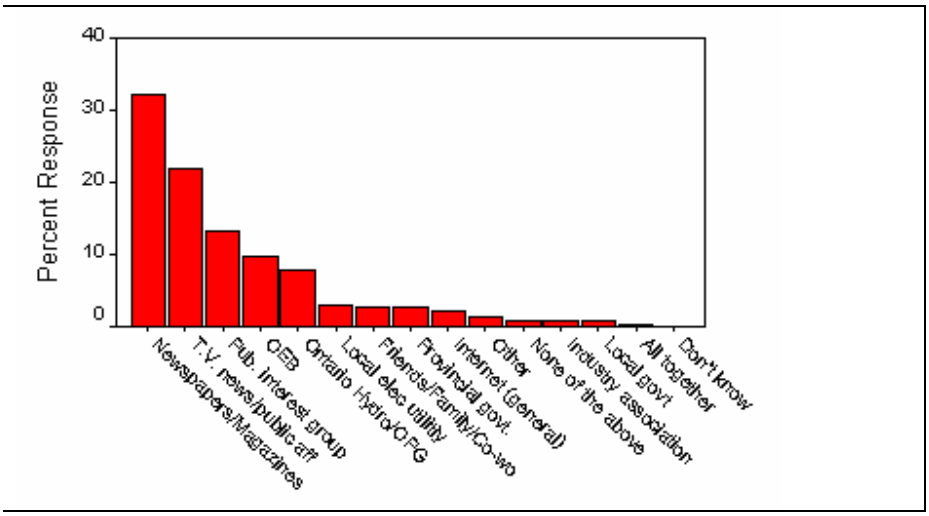
Figure 2.3.9 – Interviewee Response to Importance of Impacts



Decision Partners Inc., 2005.

Trusted Information Sources about Electricity Issues in Ontario: Survey Respondents were asked about the sources they rely on for information about electricity issues in Ontario. Most Respondents said that they rely on news media (television media, magazine and newspaper; over 60% responded "yes" in each category) and that they would not rely on "official" sources, including OEB, OPG and the government, or other people (over 60% responded "no" in each of these categories). When asked to choose the single most believable source, over 55% of Respondents chose media; "official" sources were much less favoured.

Figure 2.3.10 – Rated Most Believable Source



Decision Partners Inc., 2005.

2.3.5.4 Stakeholder Workshop Highlights

OPA invited stakeholders who participated in the mental models interviews to attend a workshop, designed and facilitated by Decision Partners and held in Toronto on November 3, 2005. Almost 40 of the 62 Interviewees participated.

Workshop Purpose: The purpose of the workshop was to share information and to engage Industry and Non-industry stakeholders in dialogue on values, tradeoffs and tough choices on key challenges. The insight gained at the workshop was used to inform OPA's advice to the Minister of Energy on supply mix.

Key Activities: The workshop design and facilitation enabled open, frank discussion on the issues and challenges that mattered most to Participants. Four small breakout groups were formed to reflect the different backgrounds, interests, and perspectives on electricity issues among Industry and Non-industry stakeholders. Workshop activities (in order of the agenda) included the following:

- Sharing with workshop participants:
  - Highlights from the one-on-one research conducted by Decision Partners on the need for electricity in Ontario and consideration of the balance of supply mix elements;
  - Findings from the parallel web survey conducted by Decima Research;
- Using the research findings as a basis for dialogue to gain insight from participants in the first breakout session on:
  The primary goal and key values regarding electricity supply in Ontario;
  The criteria stakeholders will use to judge the elements of an appropriate supply mix portfolio for 2020;
- Framing the challenge: Amir Shalaby of OPA discussed the challenge of building an appropriate supply mix portfolio for 2015-2020;
- In the second breakout session two of the groups discussed specific challenges related to long term planning of the supply mix, first in the short term, 2005-2015, then in the longer term, 2015-2025;
- The other two groups identified and shared their views on the challenges regarding effective public policies within and between all levels of government, the benefits, the impediments or barriers, and the opportunities to facilitate. In addition, the groups addressed the interaction between public policies and private interests.
- Each of the groups presented the highlights of their discussion at the plenary session at the end of the workshop. Each group selected a spokesperson who presented the highlights from his or her groups' discussion. At the close of the Workshop, Amir Shalaby and Mary Ellen Richardson thanked the Participants for their thoughtful discussions and discussed how the results of stakeholder consultation process would value the Supply Mix advice.

Top-line Workshop Highlights: Participants used the insight from the research – along with the brief overview of the supply mix challenge by Mary Ellen Richardson and Amir Shalaby of OPA – as the basis for dialogue in the breakout sessions. The result was very rich dialogue by all of the breakout groups.

A primary observation is that the discussion in all groups focused on similar key issues. These broad issues emerged regardless of the specific questions that were posed for discussion in the breakout, suggesting that they were important issues to Participants:

- Stakeholder values regarding electricity in Ontario and the criteria for evaluating elements of the supply mix advice;
- The ability of the public to understand the challenges of the supply mix advice and the need to fill their information gaps;
- The challenges of supply mix planning and electricity planning more broadly;
- Public policy challenges, including the integral inter-ministerial relationships and relationships between the levels of government, and their impact on electricity planning and implementation;
- Specific public challenges of public versus private interests, including NIMBY; and

- Considerations on the role of OPA and Participants' advice to the Minister.

Breakout Group Discussion Highlights – Session One

The following highlights from Session One reflect statements made by individual Participants during discussions. Unless specified, statements should not be interpreted as consensus among the Participants.

In the Session One, groups were led through a broad discussion and asked for comments and observations on the following:

- The primary goal and key values regarding electricity supply in Ontario.
- The criteria stakeholders will use to judge the elements of an appropriate supply mix portfolio for 2020 – 2025.

Participants were initially asked for their general observations on the research. For example:

1. *What are your first thoughts on values and criteria, based on what you saw in the research?*
2. *What did the research confirm for you regarding stakeholder values and criteria? Any surprises?*
3. *Discuss/review the list below from the research. Thinking about values and criteria stakeholders will use to judge the elements of an appropriate supply mix, is anything missing?*

Criteria and Values

In general, Participants accepted the research results regarding the key goals and priorities of stakeholders, which showed that availability/reliability/sustainability of electricity was the most important priority, followed by environmental responsibility and then cost. For the most part, the groups confirmed these values. There were some notable differences among stakeholders' goals and priorities. Key discussion points:

- Participants in all groups tended to reinforce the research findings, commenting that the availability and reliability of electricity should be the most important drivers of OPA's mandate.
- Some Participants broadened the issue of electricity needs to energy needs. They stressed the importance of considering "integrated resource planning" that incorporates such options as district heating and cooling and combined heat and power.
- Most Participants, echoing the mental models and web survey research, concluded that in the end, the Ontario economy must be the most important priority – the economy is the primary driver of all decisions in the Province.
  Participants in one group commented that the Government has not focused enough on the economic drivers for the Province.

- Some noted that the term "sustainability" is a broader issue than availability and reliability of electricity, incorporating environmental responsibility as well.
- Participants expressed surprise at the importance Survey Respondents (the Ontario Public) placed on availability and reliability of electricity, stating that their responses were more pragmatic than expected. There was some discussion that these ratings were likely confounded by citizens' private interests – such as NIMBY – and concerns about significant increases in the cost of electricity. (See also below, *Discussion Regarding an Informed Public*.)
- A similar topic raised was the how to consider the integral relationship between the following criteria: price, price volatility, environmental implications, capacity, location, etc., when evaluating supply mix options. Participants wondered if stakeholders, the public and the Governments' values were sensitive to the tradeoffs involved in the selection of an appropriate supply mix. More broadly, they wondered what is society willing to do, what is it willing to tolerate when it comes to ensuring the availability of electricity.
- When asked if there were additional values and criteria stakeholders will use to judge the elements of an appropriate supply mix that were not raised in the research, Participants suggested the following:

  Competitiveness, since "we don't want Ontario to shut down."

  The role of market focus vs. social mandate – how to value the tradeoffs between letting the market decide the supply mix and forcing supply options on the market.

  The question of who should bear the risk of investments, for example, the risk of localized generation. It was noted by two groups that the private sector should take the risk rather than the public.

  Risk management should be considered over the long-term: prudence, flexibility and ability to off-ramp if necessary in the longer run.

  Some groups thought that the cost of electricity was marginalized in terms of priority. One Participant felt that, by neglecting cost (by default, allowing it to rise), an "energy-poverty" class of people who cannot afford electricity may emerge. Regarding Ontario's competitiveness in the market, another Participant suggested, "It's power at competitive cost, not power at any cost." Others, however, argued that the lowest cost was not necessarily the primary concern.
- Some Participants suggested that the majority view held by Industry (placing a higher emphasis on advanced conventional sources than on renewables) does not reflect the priorities of the public entirely. Some stressed the importance of recognizing the high value that Survey Respondents placed on renewables.
- Some Participants thought that OPA's estimate of 1% annual growth in energy demand was too conservative.
- All groups discussed the feasibility of CDM goals.
- Participants in all groups commented on the challenges of implementing the current plans to replace phased-out coal. Participants noted the positive response to coal in the Mental Models and Web Survey research and said they hoped that these results would be carefully considered by OPA and the Minister. Participants recognized that the option to include advanced coal in the supply mix in the future likely requires continued investment in the current coal facilities.

An Informed Public and an "Energy-literate" Culture

One of the key themes that emerged from workshop was the value of the public's exposure to information and the need for an "energy-literate" culture. Many of the comments raised in the first breakout session, were underscored in the subsequent sessions and the plenary at the end of the day. Key areas of discussion included the following:

- There was noted surprise at the consistency of Survey Respondents and the degree to which their judgments and beliefs reflected those of Industry and Non-industry stakeholders. Participants interpreted this to mean that Survey Respondents were fairly well informed on electricity related challenges.
- Participants noted the difference between the ability of the public to understand the issues around electricity – "people are a lot smarter than we give them credit for being" – and the information they receive about these issues. Although it was noted that the public appeared to be more informed than was initially believed, all groups felt that information gaps would remain, specifically regarding the cost of renewables sources and the overall cost of electricity.
- Participants in each group attributed the predicted information gaps to the lack of balanced and factual information reaching the public.
- Participants thought that citizens need to know the "true cost of electricity." Some suggested that citizens need to understand the complexity of making energy available – "making energy happen" – in order to gain an appreciation for the importance of balancing the tradeoffs between electricity availability, cost, environmental impacts, etc., in general, and the tradeoffs between specific supply mix options.
- Many suggestions were offered to fill this perceived information gap:
  Some suggested using real-time metering of electricity and multi-residential electricity metering so that people become aware how much electricity they are using.
  Some suggested price discriminations and price signals so that people know "by their pocketbooks" how much energy they are using.
  Others suggested that the Government build alliances with trusted and informed members of the media.
- Participants commented that a more informed public allows for better stakeholder engagement. Several recommended societal dialogue about the importance of electricity related issues, specifically concerning the cost tradeoffs and cost-tolerances, and, to a lesser degree, the environmental tradeoffs and environmental tolerances.
  For example, Participants in one group noted a perceived difference between what politicians believe and how stakeholders and the public values coal as a supply mix option.
- Participants believed it was the role of OPA to provide this information to the customers and ratepayers in an objective and balanced manner. They also noted that the government tends to set the information agendas -- focusing on renewables and CDM – and does not provide the whole story.

Breakout Group Assignments – Sessions Two and Three

The following highlights from Sessions Two and Three reflect statements made by individual Participants during discussions. Again, comments should not be interpreted as consensus unless specifically indicated.

After a presentation by Amir Shalaby on specific challenges in developing an appropriate supply mix, the groups reconvened and worked through a series of questions. Each group selected a spokesperson who presented highlights from the group discussions.

Groups 1 and 2 joined together (as some Participants had to leave at noon) and worked through the challenges of building an appropriate supply mix, first, in the short term (2005-2015), then in the longer term (2015-2025). The following questions were asked in Sessions Two and Three as they pertain to each timeframe:

1. What barriers do you see to achieving an appropriate supply mix?
2. Given the barriers defined, what are the toughest choices – tradeoffs – that will need to be made?
3. What strategies would you recommend for addressing these challenges?

Groups 3 and 4 addressed issues related public policy challenges in Session Two, guided by the following questions:

> *At present, a number of federal and provincial departments influence Ontario electricity policies, including those related to long term planning. Soon municipalities will play a greater role in electricity planning. Thinking about OPA's mandate to develop a long term electricity plan for the Province:*
>
> - *What are the key challenges regarding electricity policies that need to be addressed if Ontario is to have a reliable electricity system both short and longer term? (open question)*
> - *What are the most significant inconsistencies between provincial departments? How might these be addressed?*
> - *What are the most significant inconsistencies between government levels – federal, provincial and municipal? How might these be addressed?*
> - *What are the most significant challenges for municipalities given their expanding role? How might these be addressed?*

In Session Three, Groups 3 and 4 addressed challenges related to private versus public interest, guided by the following questions:

- *What are the key challenges regarding private vs. public interests that need to be addressed if Ontario is to have a reliable electricity system both short and longer term?*
- *What strategies would the group recommend for addressing these challenges?*

All of the groups were asked:

What considerations does the group have for OPA to take forward as it prepares its advice to the Minister?

2.3.5.5 Supply Mix and Electricity Planning Challenges

The challenges of electricity planning in the short- and long-term were the primary focus of discussion in the combined Groups 1 and 2. Since these issues are often linked with public policy challenges (the assigned topic in Groups 3 and 4), many of the topics also arose in Groups 3 and 4. Highlights from discussions include the following:

- Participants in all groups noted that supply mix advice is more than just choosing among fuels. It must include fuel type, size and location. There was general agreement in the groups that the supply mix challenge is more significant, in the short- and long-term, than people generally recognize. One Participant's advice to the Minister was to "start acting like we're in an emergency."
- A primary theme of the Workshop was the time-frame of planning. The upcoming Integrated Power System Plan (IPSP) is not a one-time plan and must be continuously revised to reflect the changing energy needs, life-span of existing technologies, new technologies and changing policies. To this end, some suggested that OPA should "keep its finger on the pulse of technology and the market."
- Risk and uncertainty were mentioned by Participants in all groups. Commenting on Amir Shalaby's presentation of the challenges of supply mix planning, Participants in two groups commented about the uncertainty that the supply mix options already in planning in the short term were all feasible and wondered about contingency planning.
- Many Participants emphasized that the real risk is in the implementation of the Integrated Power Supply Plan (IPSP) in the short- and long-term:
  Difficulty siting of both transmission and generation facilities was mentioned as a significant barrier. Siting issues were raised at a number of points throughout the discussion in all groups.
  Labour shortages (to build and maintain new generating capacity) was raised as a critical issue, as Ontario will lose 50% of its skilled worked force in the next five years, primarily through retirement. Participants suggested that there must be government action now to encourage investment in this technical infrastructure.
  Many Participants talked about the importance of including risk in the supply mix advice, especially concerning planning for catastrophic events. Specifically mentioned was the impact of weather on Ontario's need to rely on other Provinces and the United States for electricity supply.
  Another primary theme of the Workshop was the investment risks of planning, siting and constructing facilities. This topic is discussed in further detail in *Public Policy Challenges*.

- When thinking about strategies for going forward with the long-term plan, Participants in Groups 1 and 2 stressed the following points (echoed in Groups 3 and 4 discussions).
  The need to streamline the regulatory process. As one Group stated, "reduce the number of steps and rationalize the ones that are left." One suggestion was to enact a "task force" approach, allowing Ministries that have typically dealt with energy issues in isolation to work together more holistically.
  The need to elevate electricity and energy issues in public dialogue.
  The need to engage a long-term commitment to community engagement process.
  The need to protect the electricity planning from changing governments. This point was also emphasized in Participants' advice to the Minister.
  One group focused on issues of financing and called for creative financial measures, such as loan, grant and portfolio funding.

Public Policy Challenges

Issues surrounding the public policy challenges of electricity planning and implementation were the primary focus of discussion in Groups 3 and 4. Because these issues are often intricately linked with public policy issues (the assigned discussion of combined Groups 3 and 4), many of the same topics arose in Group 2 as well. A key theme of the Workshop was the relationship between the three levels of government – federal, provincial and municipal. Participants discussed their influence on the efficacy of electricity planning and implementation. Highlights from these discussions include the following:

- Participants noted the challenges of alignment between and among the three levels of government and recognized that the three levels have different priorities – the Federal government has Kyoto obligations, the Provincial government has an obligation to supply electricity, and Municipal government is focused on economic development and electricity siting.
- All of the groups discussed the importance of and need for open and cooperative inter-Ministerial relationships between such entities as the Minister of Energy, the IESO, the Minister of Public Infrastructure, Minister of Finance, Minister of Natural Resources (environmental assessments), and every Deputy Minister in the Cabinet.
  Participants in two groups mentioned the "silo effect"; i.e., Ministries acting alone and not talking to one another.
- International policies, especially Kyoto obligations and U.S. environmental standards, were cited as public policy challenges.
- Municipal government involvement in electricity planning was a particular focus of discussion in all groups. They felt that municipalities have not had to consider energy previously, and that were not yet equipped to properly handle these decisions.
  The Municipality Planning Act, which does not do enough to shift the barriers of effective implementation at the municipal level, was specifically cited.
  Participants commented that municipalities often do not appreciate the gravity of electricity needs and that this lack of understanding leads to NIMBY-ism.

- Participants commented that the above-noted challenges are a major constraint on effective electricity planning and implementation in both the short- and long-term.
  All Groups specifically mentioned the regulatory approval process and linked the challenge to those noted above. One group suggested that the number one problem is "getting anything done."
  Two issues that arose in most groups was the timing of the approval process and regulatory certainty. Participants stressed that investors need more certainty in the approval process and that certainty (in other words, if all the requirements are met, approval will be granted) was a bigger constraint than timing. One Participant suggested: "One process. One decision. One appeal. Certainty is the key."
  Participants in all groups acknowledged the societal role of the approval process. One group emphasized the appropriate forum for local public discussion that the approval process provides, and suggested that removing this process would likely lead to greater problems.
- Workshop Participants in all groups offered suggestions for improving Municipal involvement in electricity issues, including the following:
  There should be a move toward differential pricing of transmission or localized marginal pricing – that is, communities that house generating facilities would pay less for their electricity.
  OPA should respect the local values and stress the tangible benefits of generating capacity, such as jobs and economic benefits.
  Municipalities should be encouraged to look more holistically at land use and energy use – as they do for water use.
  One Participant indicated that there is a lot of local leadership and interest in energy planning and that concrete tools are needed to enable local leaders to take action.

Public and Private Interests and NIMBY

Two specific public policy challenges – public vs. private interests and NIMBY – were raised in all groups' discussions and were intricately linked to other major discussion topics. For Participants, these issues should permeate any discussion of electricity planning, including OPA's supply mix advice.

- The question of public interests vs. private interests was a primary theme, emerging in all groups.
  One group asked whether electricity is a public or private good, calling it a question for open debate.
- Another major theme of the workshop was the interplay between societal and private interests.
  Challenges related to NIMBY-ism were mentioned in each major discussion. NIMBY-ism was noted as a particular challenge at the municipal level. These issues were closely linked with discussion about informing the public.

OPA's Role and Advice to the Minister

Participants in all groups mentioned the role of OPA in electricity planning. The following highlights emerged from discussions about advice to the Minister.

- Participants in all groups acknowledged the challenges OPA faces. They applauded OPA's efforts thus far and encouraged the Minister to support OPA in whatever capacity it needs to fulfill its mandate.
- Participants in all groups noted that OPA's role is to lay out the options for the Minister and not be too prescriptive in its advice.
  Rather than prescribing specific percentages or supply options, they suggested OPA prescribe more broadly with respect to issues of diversity and flexibility. OPA can provide leadership in creating a shared understanding of these issues and lead in acceptable solutions. One group suggested that OPA should "create the rules, not the roadmap." Congruently, many Participants thought that the market would take care of the details if the values put forth are consistent with social mandates.
  A few commented that the market would not reflect social mandate. Renewables were cited as an example where a social mandate concerning environmental impacts requires expensive solutions that would not be feasible in the market alone.
- Two groups urged Government to leave the planning and implementation to expert, independent agencies. One group noted, "Government is good at responding to what people say they want, through broad policy, but lousy at getting something done. So leave the details to the experts." There was recognition that this is difficult in practice.
- Participants in two groups also commented on the narrow scope of OPA's mandate: to provide advice to the Government on electricity policy. One group stressed that OPA cannot and should not address other challenges, such as industrial policy.
- In offering advice, Participants suggested that key Provincial Ministers and staff should be engaged in the supply mix process as soon as possible – before the Advice is sent to the Minister – and that technical training might be offered to help them understand the report.
- Participants stressed the importance of the Minister's full understanding of the integrated nature of the supply mix advice and the implications of policy decisions. One group commented that the background research should be made transparently available to the Minister.
- Participants emphasized that OPA must be prepared to play an active communication role to explain (and defend) its advice in a public forum.
- Similarly, some Participants commented that the government must be transparent in their decision making process.
- There was concern expressed by all groups about how the Supply Mix Advice would be used by the Minister. Some Participants stressed that the Government must make tough choices and must avoid "cherry picking" among supply mix elements and options. They noted that the supply mix portfolio was a system solution, so it was not possible to "cherry pick" without having a significant negative influence on other elements of the system.
- Participants suggested that energy-planning must be non-partisan – "take the political risk out of an essential service." Again, it was noted that this is difficult in practice.

2.3.6 Appendix: Lists of Newspaper, Submissions, Presenters and Participants

Call for Written Submissions – Newspaper Advertising Listings

Barrie Examiner
Belleville Intelligencer
Brantford Expositor
Brockville Recorder
Chatham Daily News
Cobourg Daily Star
Cornwall Standard Freeholder
Fort Frances Daily Bulletin
Guelph Mercury
Hamilton Spectator
Kenora Daily Miner
Kingston-Whig Standard
Kitchener/Waterloo Record
Lindsay Daily Post
London Free Press
Niagara Falls Review
North Bay Nugget
Orillia Packet & Times
Ottawa Citizen
Ottawa Sun
Owen Sound Sun Times
Pembroke Observer
Peterborough Examiner
St. Catharines Standard
St. Thomas Times Journal
Sarnia Observer
Sault Ste Marie Star
Simcoe Reformer
Stratford Beacon Herald
Sudbury Star
Thunder Bay Chronicle Journal
Timmins Daily Press
Toronto Star
Globe & Mail (National Edition)
Toronto Sun
National Post (National Edition)
Welland-Port Colborne Tribune
Windsor Star
Woodstock Sentinel Review
Turtle Island News
Ottawa Le Droit (French)
Toronto L'Express (French)

Submissions from Individuals

Aiden Abram
Wendy Aoki
Helen Armstrong
Richard Arsic
Glenn Bartley
Irene Beinarovics
Bill Bes
Anne Boychuk
Andrea Bradley
Cathie Brenner
Douglas Campbell
Andrew Colombo
Colin Creasey
Roger Dibben
Marjut Dunker
Lawrence Dunning
Henryk Dziedzic
Roy L. Edwards
Steve Eng
Janis Epners
Helen Gerson
Jack Goering
Bette-Ann Goldstein
Mark Grant
D. Green
F.R. Greening

Judy Greenwood-Speers
Aaron Hamilton
Danny Harvey
Margaret Hastings-James
Keith Heino
Lloyd Helferty
Cate Henderson
Herbert Hess
Sean Howard
Terry Howes
Roy Hrab
Tom Hughes
J.J. Hunt
Rhys Jenkins
Kevin Jones
Corey Jubenville
Bryan Karney
David Kelman
Anthony Ketchum
Jan Krasnodebski
D. and A. Kuhl
Dale Lane
Stephanie Lane
Jackie Lavender
Vivien Leong
Alain Levesque
Brad Liptrot
Alex Lisman
Leslie Luxemburger
John Maccio
Elisha MacMillan
Tanya Markvart
Tanya Markvart
Erin Martijn
Wendy McDonnell
John McGee
Allan and Dorothy McKeown
Leanne Michie
Cameron Miller
Suzanne Mogensen
Cory Morningstar
Kari Morrison
Dawn Nichols
Scott Norris
Stan Pejovic
Josephine Perkins
Anna Przychodzki
Sylvia Przychodzki
Amber Pulleyblank
Josh Rachlis
Melanie Ransom
Carol Richardson
Ian Rowlands
Darren Ruddock
James Schaefer
Paul Serruys
William and Edith Shore
Nan Shuttleworth
Mark Singh
Bill Strong
Gord Taylor
Joe Taylor
David Toms
Michael Trebilcock
Fong Tsang
Stefan Tylak
Saundi Vivian
Paula and Alan Warren
David Wills
Anthony R. Wilson
Eljay Wood
Deborah Woods
Marc Xuereb
Bill (Last name withheld)
Shannon, Garvan, Desmond and Jon (Last name withheld)

Submissions from Companies, Groups. Organization, Entities

Aiken & Associates LLC.
Association of Major Power Consumers of Ontario (AMPCO)
Association of Municipalities of Ontario (AMO)
Association of Power Producers of Ontario (APPrO)
Atomic Energy of Canada Ltd. (AECL)
AWS Public Affairs Consulting
Bruce Power
Caledon Clean Air Clean Energy Project
California Energy Commission
Cameco Corporation
Canadian Bioenergy Association (CanBIO)
Canadian Chemical Producers' Association
Canadian District Energy Association
Canadian Energy Efficiency Alliance
Canadian Environmental Law Association/Pembina Institute for Appropriate Development
Canadian Manufacturers and Exporters
Canadian Mortgage and Housing Corporation
Canadian Nuclear Association
Canadian Nuclear Society
Canadian Nuclear Workers Council
Canadian Solar Industries Association (CanSIA)
Canadian Wind Energy Association (CanWEA)
Christian Farmers Federation of Ontario
Citizens For Renewable Energy
Clean Affordable Energy Alliance
Cogen Canada
Conference Board of Canada
Coral Energy Canada Inc.
David Suzuki Foundation
Durham Strategic Energy Alliance
Electricity Market Investment Group
Electro-Federation Canada
eMeter Corporation
Enbridge Gas Distribution
Energy Council of Canada
Enersource Corporation
General Electric Canada
Greenpeace Canada
High Park Group
Hydro One Networks Inc.
INCO Ltd.
Independent Electricity System Operator (IESO)
Industrial Gas Users Association
Intelaport Networks Inc.
International Innovative Systems
Men's Professional Group
Millwright and Machine Erectors, Local 1007
Mountain Equipment Co-op
Next Energy Geothermal Solutions
Niagara Windpower Inc.
Nishnawbe First Nations
Northern WindPower Inc.
Northwatch
Office of the Honourable Dwight Duncan
On Power Systems Inc.
Ontario Chamber of Commerce
Ontario Clean Air Alliance
Ontario Environmental Industry Association (ONEIA)
Ontario Federation of Agriculture
Ontario Mining Association
Ontario Power Generation Inc.
Ontario Region Indian and Northern Affairs Canada
Ontario Society of Professional Engineers
Ontario Sustainable Energy Association
Ontario Waterpower Association
Orange Wind, Orangeville and Dufferin Wind Co-op
Organization of CANDU Industries
Pollution Probe
Power Up! Renewable Energy Cooperative

Power Workers Union
Provincial Council of Women of Ontario
ROBBERT Associates Ltd.
Sarnia Lambton Chamber of Commerce
Sierra Legal Defence Fund
Social Housing Services Corporation
Society of Energy Professionals
The Sustainable Scale Project
Thunder Bay Economic Development Department
Toronto Board of Trade
Toronto Environmental Alliance
Toronto Medical Officer of Health
Total Energy Advice and Management Ltd.
U of T Energy Sustainability Community
Union Gas Ltd.
WebGen Systems (Encompass Technologies)
Aiken & Associates LLC.

Stakeholders Consulted in Expert Interview Sessions

Association of Major Power Consumers in Ontario (AMPCO)
Association of Power Producers of Ontario (APPrO)
Atomic Energy of Canada Limited
Bruce Power
Building Owners and Managers Association
Canadian Nuclear Association
Canadian Solar Industries Association
Canadian Wind Energy Association (CanWEA)
Coral Energy Canada Inc.
David Suzuki Foundation
Electricity Distributors Association
Energy Council of Canada
Fuel Cells Canada
Greenpeace Canada
Hydro One Networks Inc.
Independent Electricity System Operator (IESO)
National Energy Board
Natural Resources Canada
Nishnawbe Aski Development Fund
Ontario Clean Air Alliance (OCAA)
Ontario Power Generation
Ontario Waterpower Association
Pollution Probe
Power Workers Union
Social Housing Services Corporation
Sustainable Buildings Canada
The Pembina Institute for Appropriate Development
Toronto Environmental Alliance
Stanislav Pejovic, Bryan Karney and Andrew Colombo, University of Toronto Department of Civil Engineering
Ian Rowlands, University of Waterloo Department of Environmental Studies

In-depth Interview Stakeholders List

Kim Allen	Professional Engineers Ontario
Bruce Ander	Markham District Energy
Marc Auger	Informed Participant
Greg Baden	Coral Energy
Marcel Beaubien	Informed Participant
David Boothby	Former Chief of Toronto Police
Lorin Busaan	Ontario Energy Association
David Butters	APPRO
Tom Charette	Canadian Federation of Independent Business
Barry Chuddy	Enersource
Dean Comand	Stelco
Duane Cramer	Sithe
Brian Doxtator	Hydro Ottawa
Robert Fleming	Informed Participant
Lauri Gregg	Falconbridge
Bill Hale	Informed Participant
Joan Huzar	University of Toronto
Kevin Loughborourgh	Enwave
Don MacKinnon	Power Workers Union
Richard Marceau	University of Ontario Institute of Technology
David Martin	Greenpeace
Sonia Mistry	Ontario Chamber of Commerce
Ian Mondrow	Direct Energy
Paul Norris	Ontario Waterpower Association
Taras, Dr. Obal	Maxxam Analytics Inc.
Leigh-Anne Palter	EPCOR
David Podruzny	Canadian Chemical Producers Association
Gary Polonsky	University of Ontario Institute of Technology
Shane Pospisil	Ontario Energy Association
Ian Rowlands	University of Waterloo
Jeffrey Smith	Chartwell Inc.
Shawn-Patrick Stensil	Greenpeace
Keith Stewart	Toronto Environmental Alliance
David Surplis	Council of Ontario Construction Associations
David Sword	Duke Energy
Linda Thom	Informed Participant
John Thompson	Mackenzie Institute
John Todd	Elenchus Research Associates
Maurice Tucci	Electricity Distributors Assocation
Fred Ware	Hudson's Bay Company
Wally Wells	Wells Infrastructure Group Inc.

Mark Winfield	Pembina
Melinda Zytaruk	Ontario Sustainable Energy Association

2.4 What Are Other Jurisdictions Doing?

This section places the Ontario Power Authority's (OPA's) supply mix advice into the context of approaches adopted in other jurisdictions regarding integrated resource planning (IRP), renewable energy supply options, conservation and demand management (CDM), and environment assessment approaches and results.

2.4.1 Key Findings

- IRP approaches give equal consideration to demand and supply options and therefore can give careful analysis to CDM options, as well as renewable technologies and policy issues
- OPA's current approach on "supply mix" advice falls generally within the definition of IRP, but could be characterized as "modified IRP" because, like California, policy favours demand and renewable supply options
- CDM programs are an integral part of electric system planning and policy in many jurisdictions worldwide; CDM programs have the ability to reduce or reshape demand loads, provide direct and indirect economic benefits, and mitigate environmental impacts
- No jurisdiction has "unfettered" competitive markets and all recognize regulatory planning intervention as a backstop for supply adequacy; IRP has re-emerged in many jurisdictions as a required planning methodology. In this sense, Ontario is not atypical
- Advances in computing power and increased familiarity with risk and probability concepts have moved risk analysis beyond simple decision tree analysis to more sophisticated scenario and risk/return analysis, although using it for analyzing plans with a full range of demand and conventional and alternative supply options is still relatively rare
- A common approach is to use portfolio techniques only to analyze the most preferred mix of conventional supply options, then to use this initial plan to determine the economic criteria (such as avoided costs) that are then applied in the determination of the amounts of renewables and CDM that are economic
- International Energy Agency (IEA) has estimated that one-third of new power generation investment in OECD countries will be in renewable energy over the next 30 years
- Technology standardization and familiarity by financiers are increasing sources of renewable energy investments; a range of financial interests (commercial lenders, venture capitalists, banks) is stimulating private investment, especially in Europe
- Renewable energy manufacturing, operations and maintenance are having a substantial impact worldwide on job creation
- Renewable energy sources supply 17% of the world's primary energy, from sources including traditional biomass, large hydropower and new renewables (small hydro, modern biomass, wind, solar, geothermal and bio-fuels)

2.4.2 Introduction

The OPA shares with Ontarians and electric industry stakeholders the optimism that long-term integrated planning can and will work for Ontario.

Ontario is not alone in this endeavour. While the adoption of competitive markets for generation in recent years did have the effect of diminishing the influence and prevalence of planning, there is still a rich world of experience from which Ontario can draw from in Canada, North America, Europe, and around the world. On IRP, there is experience in British Columbia and the U.S. Pacific Northwest; in conservation and demand management (CDM) there is 30 years of experience in California, and valuable experience also in other states; and in renewable energy sources, Germany and Denmark have led the way.

Regarding markets, IRP can co-exist in a complementary fashion with competitive markets for generation. The current "hybrid" model in Ontario is an example. Competitive generators retain the option of developing resources on their own initiative to sell under contract or into the market. IRP, for its part, identifies resources needed after consideration of any such resources that have been committed. This leads ultimately to RFPs for specified amounts and types of resources, where some form of financial and/or risk reduction incentives is offered to successful respondents. In fact, some or all the resources may end up being bid into the market, depending on the structure of the RFPs.

2.4.3 Integrated Resource Planning

2.4.3.1 Origin and Development of IRP

IRP, as currently understood, can be characterized by two objectives. The first is to place demand and supply options on an equal basis. The second is to consider all supply options on an equal basis, be they distributed or centralized options, or renewable or conventional ones. The modern IRP study and decision-making processes have substantial public and stakeholder input, and environmental and risk considerations are important decision variables, along with cost.

Electric power system planning started as a comparison of centralized generation options. The availability of resources, be they coal, hydroelectric or eventually nuclear, governed the range of options to be chosen from, and cost/economics was the main decision criterion. It was almost completely a private matter between the generating companies and their regulators or governments, with little or no public input. Risk considerations in electric power planning were either strategic in nature, e.g. diversification of resources or suppliers, or technical, e.g. in the determination of appropriate reserve margins. Approvals for building the generation and any associated transmission were obtained relatively straightforwardly, with transmission issues being largely reduced to matters of cost.

By the 1970s, environmental concerns received increased attention and environmental assessments (EAs) became standard. With EAs, environmental impacts necessarily became a much larger part of the decision analysis. Public consultation as part of the planning process also gained wide spread acceptance during this period.

In the late 1980s the idea that demand-side options could be an economic alternative to new generation gained acceptance and IRP was started. Renewable and often decentralized resources, such as wind, were also gaining in acceptance and also needing to be incorporated into the decision framework.

2.4.3.2 IRP and Competitive Markets

In the 1980s and 1990s centralized planning fell into disuse or disrepute in many jurisdictions, and a new paradigm for operating the electric power sector came to the fore. At this point, it was believed that only transmission and distribution were considered natural monopolies and generation should be opened to competition. The change was started in the U.K. with the dissolution of the Central Electricity Generating Board. Alberta was the first jurisdiction in North America with a competitive market for generation, followed by California and other states and eventually Ontario in 2002.

In all of these jurisdictions a surplus of generation existed at the time of market opening (which kept down prices and removed the urgency for new supply). In the longer term, the theory went, when new generation was required, developers would see the possibility of making a return on their investment, and they would build appropriate new generation plant, and do so without governmental or regulatory intervention. In effect, market forces would remove the need to plan for new generation resources.

In California, the selected design of the market proved to be flawed, permitting manipulation of market price by suppliers of generation and power marketers. The major utilities, which were required to purchase power at the exorbitantly high market prices and sell at an artificially low price designed to protect consumers, faced bankruptcy. Eventually, there was political intervention.

With these problems occurring, in combination with the demise of energy trading giant ENRON, investor confidence was effectively destroyed and the market failed to produce needed new resources. These developments in turn slowed or reversed deregulation initiatives, leaving markets in some reduced form in Alberta and Ontario, and much of the U.S. northeast and midwest, Texas and California.

Moreover, where markets continue, no jurisdiction has the type of "unfettered" competitive market that was the original vision – all recognize the need to provide some sort of regulatory planning intervention as a backstop to ensure an adequate supply of generation. In several of

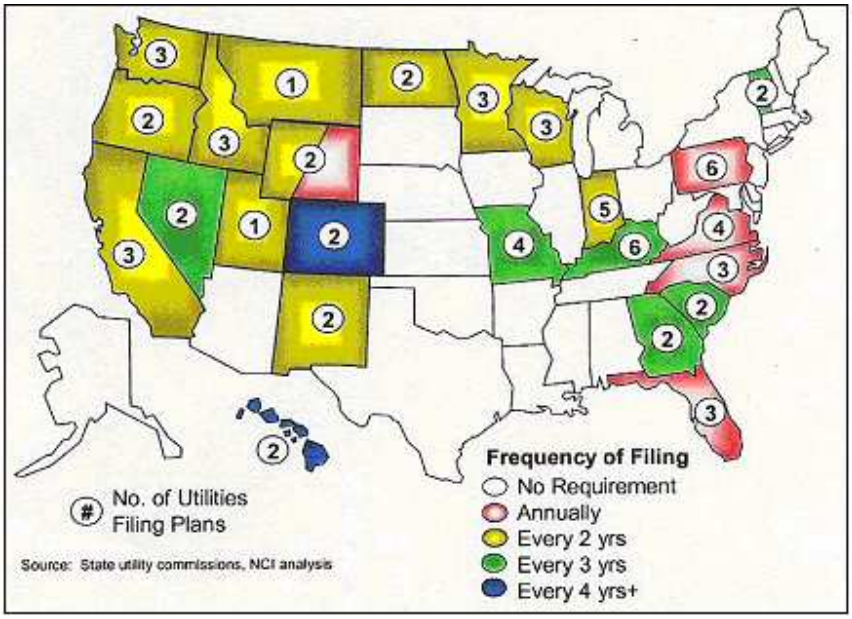
these jurisdictions, as well as in others not having markets, IRP has re-emerged as a required planning methodology. In this sense, Ontario is not atypical.

2.4.3.3 Re-emergence of IRP

California, was one of the first jurisdictions to recognize that total reliance on market forces would not ensure adequacy of electricity supply, and regulatory intervention was necessary, in particular a return to planning for new resources. In some areas without and no longer contemplating markets there was state intervention that led to the re-emergence of IRP as a required planning methodology.

The Figure 2.4.1 shows those states in the U.S. returning to or continuing with formal resource planning in the face of wholesale market concerns.

Figure 2.4.1 – Resource Planning Requirements by State



Source: Navigant Consulting

In a number of instances, state governments have adopted as policy the encouragement of alternative generation, conservation and demand management. A variety of techniques have been developed, including the issuing of portfolio guidelines. These guidelines have specified the proportion or amounts of new demand or renewable supply resources.

Analyzing CDM and alternative technologies on an even playing field basis with conventional supply options is not easy. There can be significant differences in the number, scale and maturity of the technologies involved, in data availability, and in the risks and flexibilities

inherent in the technologies. As a result, approaches to the planning analysis framework have varied considerably.

Analyzing risks can be very data and computing intensive. Early work, beyond the analysis of reserve margins, was based on either scenario analysis or simple decision tree analysis. With the advances in computing power and increased familiarity with risk and probability concepts, analysis has become more sophisticated and risk/return analysis, using portfolio concepts, is now widespread. However, its use for analyzing plans with a full range of demand and conventional and alternative supply options is still relatively rare.

A common approach is to use portfolio techniques only to analyze the most preferred mix of conventional supply options, then to use this initial plan to determine the economic criteria (such as avoided costs) that are then applied in the determination of the amounts of renewables and CDM that are economic.

The final stage is to use these levels of CDM and renewables to adjust the supply plan, i.e. to develop the final plan. This process of adjustment for economic CDM and renewables reflects the belief that CDM and renewable programs are generally limited in their contributions, but are low risk options given their short lead times.

Typically IRP processes, distinct from the early planning processes, allow for public and stakeholder involvement in the formulation of the plan, with considerable variation in their scale and approach.

Another new development in the planning methodology is the explicit inclusion of action plans. These plans document the actions that are needed before the next iteration of the planning cycle (typically one to three years) to implement the vision laid out in the IRP. Generally, a planning follow-up action is not undertaken before it is needed in order to keep to the vision. The premise is that by waiting, the decision surrounding the action will be better informed. Sometimes, however, an action will be taken prematurely to provide insurance against uncertain events or to keep open a future option.

The action plan emerging from an IRP typically itemizes the requests for proposals that will be issued, leading either to outright purchase contracts or contracts with contingent support payments.

The methodology and resulting plans from IRPs in a number of other jurisdictions are described in the next section.

2.4.3.4 Recent IRPs in Other Jurisdictions

In reintroducing IRP to Ontario, OPA has examined some of the leading current examples of IRP in other jurisdictions for guidance. In the following review, OPA examines IRP exercises

performed by five U.S. jurisdictions (Puget Sound Energy, PacifiCorp, California, Idaho Power and Hawaii Electric), and BC Hydro in Canada.

Puget Sound Energy: 2005 Plan

Puget Sound Energy (PSE) is an integrated electricity and gas utility in Washington state. It establishes and periodically updates a Least Cost Plan as part of its long-term resource acquisition and management strategy development. This document satisfies Washington state requirements regarding least cost planning and provides an update of the results of the electric and gas Least Cost Plan analysis process and long-term resource strategic direction. PSE completed its first IRP in 2002 and its second in 2005.

Methodology

In its 2005 plan, PSE elected to analyze the key issues using a scenario approach. This approach was selected because of the magnitude of the key issues and because many of the uncertainties are independent (i.e. availability of transmission is not dependent upon gas prices or greenhouse gas regulation). Since each of the scenarios represents a unique future, PSE developed a consistent set of input data for each. The scenarios include one labelled "business as usual" and others that provided "stress tests" regarding factors such as higher demand for electricity and high costs to be applied to CO_2 emissions.

Each scenario is analyzed using electric market simulation models. PSE uses three primary models for least cost planning. The first, the AURORA model, analyzes the western power market to produce hourly electricity price forecasts for the entire 20-year planning period. The model is applied to each of the chosen scenarios.

On the basis of the AURORA results, candidate portfolios are developed and analyzed in the Portfolio Screening Model (PSM), which tests the portfolios to evaluate PSE's long-term incremental portfolio costs. Stress tests are applied through both "Monte Carlo"[1] analysis of uncertain variables, such as hydroelectric output and gas prices, as well as the five scenarios.

Finally, the Conservation Screening Model (CSM) tests demand-side resource cases to determine the most cost effective level for a given generation portfolio.

Results

Puget Sound Energy's latest plan concludes that PSE should acquire a diverse mix of generating and demand-side resources. Key analytical findings include:

[1] Monte Carlo analysis is an analytic approach that randomly samples values of uncertain variables from an assumed probability distribution (the reference being to a roulette wheel). For additional details see Part 3.5.

- Portfolios with coal resources reduce portfolio costs when included with a regional transmission solution.
- Portfolios with coal resources remain cost competitive in many scenarios. Absent a regional transmission solution, i.e. extensive multi-year transmission system upgrades, portfolio costs are generally higher, despite high transmission costs.
- Scenarios with quantified carbon dioxide emissions costs cause portfolios that include gas resources to be cost-competitive with portfolios that include coal resources.
- Accelerated energy efficiency provides more benefit to the portfolio than a constant rate of introduction of energy efficiency measures.
- Considering all scenarios, the lowest risk (but not necessarily the lowest cost) incremental portfolio is that of the 15 percent renewable and 50/50 coal & gas portfolio.
- Under current market price assumptions, near-term power bridging agreements, i.e. limited-term contractual arrangements for purchasing power, would reduce portfolio cost compared to gas resources.
- Under the Least Cost Plan assumptions, early fuel conversion (from electricity to natural gas end use consumption) could provide more benefit to the portfolio than normal fuel conversion.
- Overall, considering both cost and risk, the analysis supports the selection of a portfolio including accelerated energy efficiency, early fuel conversion, 10 percent renewable generation, and 50/50 gas and coal. This portfolio performs well across all the scenarios.

PacifiCorp

PacifiCorp is an investor-owned utility serving more than 1.6 million customers in six western U.S. states. Based in Portland, Ore., PacifiCorp has 8,426 megawatts (MW) of generation capacity. PacifiCorp operates as Pacific Power in Oregon, Washington, California and Wyoming and as Utah Power in Utah and Idaho.

PacifiCorp is committed to renewable power as a viable, economic and environmentally prudent means of generating electricity. Its IRP builds in cost of emissions, the result of which is a plan to increase its renewable power portfolio by adding 1,400 MW of renewable generation by 2013.[2]

Methodology

PacifiCorp employs a planning process involving nine modeling steps as follows:

- Step 1: Portfolio Development **-** The first step in the analytical process is the formulation of resource portfolios. The formulation consists of determining the resource need (the load and resource balance), composing candidate resource options to fill that need, and building portfolios according to development guidelines.

[2] http://www.pacificorp.com/Navigation/Navigation23807.html

- Step 2: Operational Simulation - Next, each portfolio, consisting of the existing resource base and new additions, is simulated deterministically[3] using a production cost model. That is, the model analyzes the utilization and consequently operating cost of the resources of the portfolio for all hours of the planning period.
- Step 3: Cost Analysis - Each portfolio's system operating costs are then combined with the corresponding capital costs, yielding the PVRR, Present Value Revenue Requirement, the main cost metric.
- Step 4: Screening - The performance of each of the portfolios is evaluated based on total cost (PVRR), other measures of portfolio performance, and characteristics of interest for risk analysis. This screening process results in a narrowing of portfolios to a list of candidates for risk analysis.
- Step 5: Risk Analysis - The risk analysis evaluates the performance of candidate portfolios under a large number of possible futures using Monte Carlo and deterministic scenario simulations[4].
- Step 6: Selection of the Preferred Supply Side Portfolio - Using results from the deterministic, stochastic, and scenario model runs, along with the customer impact results and non-modeling considerations, a single portfolio is selected that has the best balance of cost and risk. This is the preferred supply side portfolio.
- Step 7: Selection of the Preferred Portfolio - DSM Class 1[5] analysis is performed on the preferred supply side portfolio in order to improve further the PVRR, resulting in the final Preferred Portfolio.
- Step 8: Class 2 DSM Analysis - Once the Preferred Portfolio is identified, Class 2 DSM decrement analysis is performed to estimate the system production cost benefits resulting from DSM-related load reductions. These values will be used to evaluate potential programs going forward.
- Step 9: Stress Case Analysis - Stress case portfolios are devised and simulated to determine the impacts of base assumption changes or alternate supply options.

Results

PacifiCorp's Preferred Supply Portfolio consists of a balanced mix of resource additions, having roughly a 50:50 mix of conventional coal and combined cycle gas turbines (CCGT). The Preferred Portfolio ranks at or near the top in terms of stochastic risk. Furthermore, the Preferred Portfolio does not stand out as risky in terms of the CO_2 cost and high gas cost. Finally, the Preferred Portfolio ranks among the lowest of all candidate portfolios in terms of deterministic present value of revenue requirement (PVRR).

[3] That is, the analysis is performed using expected values of the various parameters, i.e. uncertainty in these parameters is not taken into consideration. In contrast, stochastic analysis explicitly considers the probability distribution for such parameters, for example, the Monte Carlo method.
[4] See Part 2.8 for additional detail on deterministic scenario simulations.
[5] According to PacifiCorp definitions, Class 1 is Load Control, Class 2 is Conservation and Physical Changes Made to Reduce Energy Use, Class 3 is Price Responsive Load Reduction and Class 4 is Customer Education.

PacifiCorp's subsequent DSM analysis led to the addition of some summer load control measures that deferred the need for the supply options.

State of California – Draft Energy Action Plan II (EAP II)

The California Energy Commission adopted a version of the Energy Action Plan II in September 2005. The plan, known as the EAP II, is a joint effort of the California Public Utilities Commission and the California Energy Commission. The initial effort in 2003, EAP I, led to a policy promoting energy efficiency, renewable resources and clean power projects as the "loading order" for new resource additions in the state.[6]

Methodology

EAP II continues the strong support for the "loading order" – endorsed by Governor Schwarzenegger – that describes the priority sequence for actions to address increasing energy needs. The loading order identifies energy efficiency and demand response as the state's preferred means of meeting growing energy needs. After cost-effective efficiency and demand response, California relies on renewable sources of power and distributed generation, such as combined heat and power applications.

To the extent efficiency, demand response, renewable resources and distributed generation are unable to satisfy increasing energy and capacity needs, California gives priority to clean and efficient fossil-fired generation. There is a recognized need to improve the bulk electricity transmission grid and distribution facility infrastructure to support growing demand centres and the interconnection of new generation, both on the utility and customer side of the meter.

Idaho Power – 2004 Integrated Resource Plan

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as successor to a Maine corporation organized in 1916. Idaho Power is involved in the generation, purchase, transmission, distribution and sale of electric energy in a 24,000 square mile area in southern Idaho and eastern Oregon with an estimated population of 895,000. Idaho Power holds franchises in 72 cities in Idaho and 10 cities in Oregon and holds certificates from the respective public utility regulatory authorities to serve all or a portion of 28 counties in Idaho and three counties in eastern Oregon. As of Dec. 31, 2004, Idaho Power supplied electric energy to 440,409 general business customers and had 1,757 full-time employees.

Idaho Power owns and operates 17 hydroelectric power plants and two natural gas-fired plants. The company also shares ownership in three coal-fired generating plants.

[6] The material in this section is taken largely from www.cpuc.ca.gov.

Idaho Power relies heavily on hydroelectric power for its generating needs and is one of the nation's few investor-owned utilities with a predominantly hydroelectric generating base.[7]

Methodology

The two primary goals of the Idaho 2004 Integrated Resource Plan[8] are to:

- Identify sufficient resources to serve the growing demand for energy service reliably within the Idaho Power Company service area throughout the 10-year planning period.
- Ensure that the portfolio of resources selected balances cost, risk, and environmental concerns.

In addition, there are two secondary goals:

- To give equal and balanced treatment to both supply-side resources and demand side measures.
- To involve the public in the planning process in a meaningful way.

Idaho Power examined 12 portfolios of which 5 were selected for additional risk analysis.

Results

A diversified portfolio with some CDM programs and nearly equal amounts of renewable generation and traditional thermal generation was selected as the preferred resource portfolio. Idaho Power intends to issue requests for proposals (RFPs) to purchase the required resources.

Hawaiian Electric Company – Draft Integrated Resource Plan 2006 – 2025

Hawaiian Electric Company, Inc. (HECO), and its subsidiaries, Maui Electric Company, Ltd. (MECO), and Hawaii Electric Light Company, Inc. (HELCO), provide electricity to 95% of the state's 1.2 million residents on the islands of Oahu, Maui, Hawaii, Lanai and Molokai.

Since most of the power is generated on the west side of Oahu and most of the power is used in central and east Oahu, electricity must be transmitted east through transmission lines, which run in two primary corridors - a northern and a southern corridor. The majority of the fuel oil used by HECO utilities is residual low sulfur fuel oil that is leftover after the lighter petroleum products, such as gasoline and jet fuel, are refined from crude oil. Some diesel fuel is also used.[9]

Methodology

[7] Material in this section was taken from www.idahopower.com.
[8] www.idahopower.com/pdfs/energycenter/irp/2004_IRP_final.pdf.
[9] The material in this section is taken largely from www.hec.com/.

This is the third IRP that HECO has filed.[10] The previous plans were submitted in 1993 and 1998. HECO selected its draft preferred plan based on considerations of flexibility, invariance to changing market conditions, reasonable tradeoffs, and a balance of attributes.

After an initial screening, six candidate portfolios were examined in detail, including analysis of robustness against six scenarios (alternate futures).

Results

The plan incorporates near-term implementation of renewable supply-side resources, a diversity of fuels, aggressive DSM, combined heat and power (CHP) and conventional supply resources.

In the long term (by 2025), the draft preferred plan includes 151 MW of DSM, 61 MW of cogeneration, 51 MW of renewables (wind and photovoltaic), and 280 MW of conventional supply-side resources.

BC Hydro

BC Hydro is one of the largest electric utilities in Canada, serving more than 1.6 million customers in an area containing over 94 per cent of British Columbia's population. As a provincial crown corporation, BC Hydro reports to the Minister of Energy and Mines, and is regulated by the British Columbia Utilities Commission (BCUC).

BC Hydro operates 30 hydroelectric facilities and three natural gas-fuelled thermal power plants. About 80 per cent of the province's electricity is produced by major hydroelectric generating stations on the Columbia and Peace rivers. BC Hydro's various facilities generate between 43 and 54 TWh of electricity annually, depending on prevailing water levels. Electricity is delivered through a network of 18,286 kilometres of transmission lines and 55,254 kilometres of distribution lines. For fiscal 2005, domestic electric sales volume reached 51 TWh.

BC Hydro endeavours to provide energy solutions to its customers in an environmentally and socially responsible way by balancing British Columbians' energy needs with the concerns of the environment.[11]

Methodology

The B.C. government's energy plan calls for electricity distributors to acquire new resources on a least cost basis, with regulatory oversight by the BC Utilities Commission (BCUC).

[10] www.heco.com/images/pdf/HECO_IRP3_AG_Draft_MajorReview.pdf.
[11] The material in this section is taken largely from www.bchydro.com/.

BC Hydro provides an Integrated Energy Plan (IEP) every two years to its regulator, the BCUC[12]. Each time a review of the plan is undertaken, BC Hydro may choose to update the entire plan or focus on a particular part of the plan. BC Hydro's most recent IEP was issued on March 31, 2004. The 2005 IEP will be completed by the end of 2005 and will subsequently be completed every two years.

In developing the 2004 IEP,[13] BC Hydro sought the input of various interested parties to help understand and appreciate their perspectives and preferences related to electricity options.

As part of the 2005 IEP process, this input will be used to create a more comprehensive First Nations and stakeholder engagement process.[14] Input received will guide the planning process, and create the framework for future input into energy planning initiatives.

For its 2004 IEP, BC Hydro developed and compared portfolios encompassing a variety of resource options in order to evaluate the following key issues:

- Currently planned acquisitions: the first group of portfolios tests BC Hydro's currently planned acquisitions.
- Vancouver Island Supply: the second group of portfolios explored the Vancouver Island capacity constraint and compared the merits of on-island generation with expanding the transmission system to address the island's need for capacity.
- Future Options for Burrard: the third group of portfolios explored options regarding the future of the Burrard Thermal Generating Station.
- Resource Deferral and Advancement: the fourth group of portfolios examined the economics of deferring or advancing resources.
- Future Options for New Resource Acquisitions: the fifth group of portfolios examined future resource acquisitions and evaluated different resource types to identify the advantages and disadvantages of each.

BC Hydro constructed these alternative 20-year portfolios by first adjusting the load forecast to account for the amount of demand-side resources specified in the portfolio. Various combinations of generation resources were then added to the existing supply to serve the demand.

New resources were then scheduled based on their capacity, energy planning criteria. The schedule of resources, their costs and characteristics from the resource option database, were assembled and evaluated in the Multi-Attribute Portfolio Analysis model (MAPA), developed by BC Hydro.

[12].http://www.bcuc.com.
[13] http://www.bchydro.com/info/epi/epi18595.html.
[14] http://www.bchydro.com/info/epi/epi18590.html.

Once the schedule of new resources was determined, the portfolios were analyzed with BC Hydro's hydrological system simulation model (HYSIM) to determine the expected annual generation from each resource. The expected generation determines the annual variable cost for each portfolio, including the cost of imports and the revenue from market exports. These annual variable costs are consolidated with the capital and fixed costs in MAPA. MAPA uses the expected generation to calculate attributes that vary with the amount of electricity generated.

Table 2.4.1 summarizes the attributes used to evaluate the performance of the portfolios. These include key performance attributes linked to the objectives of the 2002 BC Energy Plan, and a number of supplementary attributes further examine the performance of the portfolios. For example, the greenhouse gas emissions and the local air emissions for a thermal resource are based on energy output and the associated emission rates.

Table 2.4.1 – Summary of Portfolio Attributes (BC Hydro)

Four Key Performance Attributes		
Attribute	**Unit of Measure**	**Objective**
Net present value (NPV)	Discounted cash flow of total cost less export revenues in real F2003 dollars (includes DSM costs)	Minimize ratepayer costs
Reliability planning criteria	Meets Criteria Yes/No	Secure and reliable supply
Private sector involvement	Percentage of new energy provided by private sector Percentage of new energy owned by private sector	IPP involvement
Clean target	Percentage of newly acquired energy (GWh) that meets the definition of BC Clean Energy	50% Clean target
Supplementary Attributes		
Attribute	**Unit of Measure**	
Rate impact	20-year change in rates net of inflation relative to the first year	Minimize ratepayer costs
Dependable capacity	MW installed capacity MW dependable capacity	Secure and reliable supply
Diversity	Number of new resource types	Secure and reliable supply
Employment	Temporary/construction (person-years) Long-term (full-time equivalents)	Social responsibility
Greenhouse gases and Local emissions	Greenhouse Gases: tonnes of CO_2 equivalent Local Emissions: tonnes of nitrogen oxides (NOx), sulphur oxides (SOx), and particulate matter (PM)	Social and Environmental responsibility
Footprint	Hectares of total surface area affected by a portfolio	Social and Environmental responsibility
Communities	Qualitative comments with respect to affected communities, First Nations and stakeholder feedback	Social responsibility

Source: BC Hydro

The portfolio analysis model (MAPA) was used to conduct scenario analysis and sensitivity analysis with system simulation results provided by the hydrological simulation model (HYSIM). Table 2.4.2 summarizes the probabilistic variables analyzed, and the scenarios and sensitivity analysis performed as part of the risk evaluation process.

Table 2.4.2 – Uncertainties Investigated in Risk Evaluation Process (BC Hydro)

Reference case		Scenario/Sensitivities Tested
Probabilistic Variable		
Hydrological variability	60 years of monthly historical stream flows (1940-2000) in 20-year sequences	Variability of inflows intrinsically reflected in the analysis of each portfolio
Scenarios		
Gas and electricity market scenarios	No single market price forecast is assumed to be a base case	Confer Energy Information Administration National Energy Board Techno-Vert High Gas Alternative heat rate
Demand scenario	Reference forecast	Low forecast High forecast
Environmental – Regulatory costs associated with GHG	No cost	10$/tonne of GHG emissions from BC Hydro and IPP generation
Sensitivities		
Financial – Discount rate	6% real	8% and 10% real
Supply: project capital cost and fixed costs, and/or IPP contract fixed cost	Expected cost	Low: -10 to +20% of expected value Medium: -10 to +40% of expected value High: -10 to +60% of expected value

Source: BC Hydro

Results

Based on the analysis, and recognizing the value of flexibility, the key conclusions of BC Hydro's 2004 IEP are:

- Power Smart 2 (DSM programs) is economic and should be continued.
- Planned efficiency improvements at BC Hydro's existing generating stations are economic and should be continued.
- A modest energy acquisition program from the private sector is warranted to meet incremental requirements and to mitigate demand and supply risks. Private sector calls should be undertaken periodically to secure low cost power, maintain energy self-sufficiency, and meet the clean energy target.

- The outcome of the Vancouver Island Call For Tenders or a change in demand will influence the timing of 230 kV cables to Vancouver Island.
- There is uncertainty about Burrard's future role. Assumptions about the future role of Burrard have a significant impact on BC Hydro's resource portfolio.
- The downstream benefits from the Columbia River should be considered as a potential option for meeting dependable capacity requirements in the near-term.
- Adding capacity at Revelstoke or Mica is the least cost approach to meeting capacity requirements. These additional units would be required in all of the portfolios studied. Therefore, the necessary studies and approvals for the fifth unit at Revelstoke or Mica should be initiated.
- All portfolios require an Interior-to-Lower Mainland transmission reinforcement. The timing of this upgrade depends on whether future supply is from remote generation or load-centred generation. BC Hydro needs the flexibility to plan for the possibility that future supply will be located outside the load centre.
- Maintain Peace River Site C because it is economic and the portfolio NPV results are relatively insensitive to different gas and electricity price scenarios.

An action plan was included as part of the 2004 plan.

2.4.3.5 OPA's IRP Analysis Framework

The approach OPA has taken for providing "supply mix" advice falls generally within the definition of IRP, but with government policy direction respecting certain resources. For this reason, the current Ontario approach can be characterized as "modified IRP", in the sense that policy interventions favouring demand and renewable supply options have been reflected. This is similar to the situation in California.

While extensive, the analysis has been somewhat constrained by the limited time available to perform it – a full IRP typically takes a minimum of one full year, and longer for a first plan. In OPA's case, the analysis has been conducted in a much shorter period – more will be done in 2006 in developing the first Integrated Power System Plan (IPSP) for Ontario.

The Ontario government has set a target of a peak demand reduction of 5 % by 2007, and a coal replacement by 2009. It has also set a goal for 5% of all generating capacity in the province to come from renewable sources by 2007 and 10% by 2010. The Minister explicitly requests that other supply options should be identified only after consideration of CDM and renewables.[15]

OPA's analysis was similar to that in the other jurisdictions described in this section – the use of portfolios of resources tested for their sensitivity to changes in key assumptions and their robustness. Analysis of DSM potential was somewhat simplified; for example, it was assumed potential is independent of portfolio makeup.

[15] See Part 2.2

With the exception of some portfolios designed to illustrate the benefits of CDM and renewables options, OPA's portfolio analysis has concentrated on the costs and risks of the conventional generation supply options after making allowance for the maximum credible amounts of DSM and renewables. For CDM, the analysis of potential was based on an understanding of the marginal costs that came from a previous study done by Navigant Consulting for Hydro One Networks Inc., since posted by the OEB.[16] [17]

The contribution of CDM to minimizing the risk involved in the demand supply portfolio has not been determined. For alternative/renewable technologies, the Levelized Unit Energy Cost (LUEC) was used as a guide to the economics, and the amounts prescribed into the plan analysis were derived as described in Part 2.6. No assessment of the impact on the risks involved was undertaken. Thus, the portfolio risk analysis has only been done with respect to the supply options required to fill the gap after CDM and renewables have been included.

A review of public and stakeholder input is included in Part 2.3.

An action plan has been formulated as part of this planning exercise in Part 1.2. It illustrates a common set of recommendations that can respond to a number of possible futures.

2.4.4 Renewable Supply Options

In the letter requesting supply mix advice, the Minister of Energy placed emphasis on the role of renewables in Ontario's future. In order to have context for the development of renewables, this section summarizes the advancement of renewable energy in other jurisdictions, as compiled by the Worldwatch Institute in its renewables 2005 global status report.[18]

Renewables 2005 provides an overview of the status of renewable energy worldwide in 2005. The report covers markets, investments, industries, policies, and rural (off-grid) renewable energy in developing countries.

The use of the term "renewable energy" throughout the report refers to "new" renewables (small hydro, modern biomass, wind, solar, geothermal and biofuels), while excluding traditional biomass, primarily used for cooking and heating, and large hydroelectric power

[16] A comprehensive history/overview of conservation in Ontario's electricity and gas sectors is available in Appendices A and B of the OEB's October 3, 2003 "Board Staff Discussion Paper on Demand Side Management and Demand Response in the Ontario Energy Sectors." See http://www.oeb.gov.on.ca/documents/directive_dsm_paper_061003.pdf.

[17] See Part 2.8 for the portfolio analysis.

[18] REN21 Renewable Energy Policy Network, *Renewables 2005 Global Status Report*. (Washington, DC, Worldwatch Institute, 2005).

(which is, however, discussed for comparative purposes). This review focuses on electricity and thermal energy generation with renewable sources.

2.4.4.1 Global Market Overview

Renewable energy supplies 17% of the world's primary energy. It includes traditional biomass, large hydropower and new renewables (small hydro, modern biomass, wind, solar, geothermal and biofuels). Large hydropower is considered renewable by some countries and not by others, but it is included in the 17% figure for the world's total renewable energy supplies. Renewable energy competes with conventional fuels in four distinct markets, including power generation, hot water, space heating, transportation fuels, and rural (off-grid) energy.

About 4% of the world's power generating capacity comes from renewable energy and 3% of global electricity production is supplied by renewable energy (excluding large hydropower). Also, tens of millions of buildings worldwide produce hot water and space heat supplied by solar, biomass and geothermal energy. An estimated 40 million homes now use solar thermal collectors, and biomass and geothermal sources supply heat for industry, homes and agriculture. Table 2.4.3 summarizes the existing capacity of several renewable energy technologies worldwide at the end of 2004, compared to world total capacity.

Table 2.4.3 – Existing Capacity of Renewable Energy Technologies Worldwide (2004)

	Existing Capacity (End of 2004)	**Comparison Indicators**
Power Generation		
Large hydropower	720 GW	World electric power capacity = **3,800 GW**
Small hydropower	61 GW	
Wind turbines	48 GW	
Biomass power	39 GW	
Geothermal power	8.9 GW	
Solar PV, off-grid	2.2 GW	
Solar PV, grid-connected	1.8 GW	
Solar thermal power	0.4 GW	
Ocean (tidal) power	0.3 GW	
Total renewable power capacity (excluding large hydropower)	160 GW	
Hot water/space heating		
Biomass heating	220 GWth	Total households worldwide = **1,600 million**
Solar collectors for hot water/heating	77 GWth	
Geothermal direct heating	13 GWth	
Geothermal heat pumps	15 GWth	
Households with solar hot water	40 million	
Buildings with geothermal heat pumps	2 million	

Source: REN21, 2005

2.4.4.2 Status of Renewable Energy Technologies

Renewable energy technologies for power generation and hot water/heating applications are at various stages of deployment worldwide. Some technologies have been in use for decades. Increased development of these technologies has been reflected by price decreases due to economies of scale and economic competitiveness. Facing costs typically higher than conventional technologies and other market barriers means that most renewables continue to require policy support.

Just as the cost of renewable energy technologies has been declining, so have the costs of conventional energy technologies. One fundamental uncertainty about the future competitiveness of renewables relates to fossil fuel prices. The higher the costs of primary fossil energy sources, the more competitive non-fossil and renewable energies become.

A summary of the most common renewable energy technologies for power generation and hot water/heating applications and their associated cost trends, is presented in Table 2.4.4.

Table 2.4.4 – Status of Renewable Energy Technologies: Cost Trends and Characteristics.

	Cost Trends and Potential for Cost Reduction
Power Generation	
Large hydro	Stable.
Small hydro	Stable.
On-shore wind	Declined by 12-18% with each doubling of global capacity. Costs now half of those in 1990, while turbine sizes have increased. Future cost reductions expected from site optimization, improved design and electronics.
Off-shore wind	Market still small. Market maturity and technology improvement expected to bring future cost reductions.
Biomass power	Stable.
Geothermal power	Costs have declined since 1970s. Costs for currently economic resources could decline with improved exploration technology, cheaper drilling techniques, better heat extraction.
Solar PV (module)	Costs have declined by 20% for each doubling of installed capacity or 5% per year. Market factors led to higher costs in 2004. Future reductions expected due to materials, design, process, efficiency and scale.
Solar PV (rooftop)	Continuing declines due to lower module costs, inverter improvements and balance-of-system components.
Solar thermal power	Costs are less than the first plants in the 1980s, which were about 44 cents/ kWh. Future reductions due to scale and technology.
Hot Water/Heating	
Biomass heat	Stable.
Solar hot water/heating	Costs moderately lower due to economies of scale, new materials, larger collectors and improved quality.
Geothermal heat	Costs have declined since the 1970s. See geothermal above.

Source: REN21, 2005

A summary of status and industry trends surrounding some common renewable energy technologies is presented in the following sections. Figure 2.4.5 illustrates the worldwide growth rates of several renewable energy technologies for both power and heating applications.

Solar PV

Grid-connected solar photovoltaics (solar PV) have been the fastest growing energy technology in the world, with total existing capacity increasing from a very small base of 0.16 GW in 2000 to 1.8 GW at the end of 2004. This represents a 60% average annual growth rate over the last five years. Grid connected solar PV applications are concentrated in Japan, Germany and the United States, with over 400,000 rooftop PV systems feeding power to the grid in these three countries in 2004. The number of building-integrated solar PV systems is growing in several countries as well, most notably with commercial and demonstration installations ranging from 10 kW to 1,000 kW. Some examples include solar PV demonstrations integrated into a subway station, (100 kW), a city hall (50 kW), and an exhibition hall (1,000 kW).

Off-grid solar PV is not exhibiting the same level of growth as grid-connected applications, with an average annual growth rate of 17%. In total, solar PV is "becoming one of the world's fastest-growing, most profitable industries". Plans for capacity expansion between 2005 and 2008 total several hundred megawatts, and in 2005 alone, from $5 to $7 billion in capital investment is estimated to be made. In 1999, the solar PV industry celebrated its first gigawatt of global cumulative production and by the end of 2004 cumulative production was over 4 gigawatts (on-grid and off-grid applications).

Solar Concentrating Thermal Power

The concentrating solar thermal power market has been relatively stagnant for over 10 years, but a resurgence of interest, technology evolution and potential investment is taking place with recent commercial plans in the United States, Spain and Israel. Solar concentrating thermal power plants use the sun's energy to create steam and drive turbines. Investors are currently considering a 50 MW concentrating solar thermal power plant in Spain.

Wind

The wind-power industry produced over 6,000 wind turbines in 2004, averaging 1.25 MW in size. In addition, wind turbine capacities continue to increase, with European manufacturers introducing prototype wind turbines in the 5 MW range. In total, wind power is growing at an average annual rate of 28%. Spain, Germany, India, the United States and Italy led worldwide wind-power expansion in 2004, with several other countries looking to develop commercial markets for wind power in the future. In addition, off-shore wind markets are emerging – the first large scale off-shore wind farm (170 MW) was completed in Denmark in 2003 and over 40 GW of development in Europe are planned.

Recently as well, renewable energy has grown into big business, as prominent large industry players, such as GE and Siemens, have bought into the wind power market. Such companies bring added competencies to the market including financing, marketing and production scale.

Hydropower

While large hydroelectric power remains one of the lowest cost energy technologies, further growth in many countries is limited due to availability of sites, resettlement issues and environmental constraints. Canada is currently the top hydroelectric power producing nation (12% hydroelectric). Worldwide, growth in large hydroelectric power has grown at just under 2% percent annually.

Small hydroelectric power development has been occurring worldwide for over a century and over half the current global capacity is in China, where nearly 4 GW (4,000 MW) was added in 2004 alone. Much small hydroelectric capacity is used in rural, off-grid applications. Technology improvements have been focused on exploiting low heads (under 15 meters) and small capacities (under 250 kW). Small hydroelectric power is growing globally at an average annual rate of between 2% and 3%.

Biomass

The biomass power and heat industry is more mature, localized, and diverse than the wind and solar PV industries, and is growing at an average annual rate of between 2% and 3%. Most biomass expansion has occurred in Europe and continuing investments are occurring in Denmark, Finland, Sweden, the United States and several other OECD countries. A recent boom in power from wood waste in Germany is levelling off, as the resource base is mostly depleted. The United Kingdom has seen growth in co-firing biomass in coal-fired power plants. In Sweden, over 50% of district heating needs are supplied by biomass.

Increasingly, small-scale biomass gasifiers are finding applications in rural areas, and demonstrations of biomass gasification for use in high efficiency combined-cycle power plants are increasing.

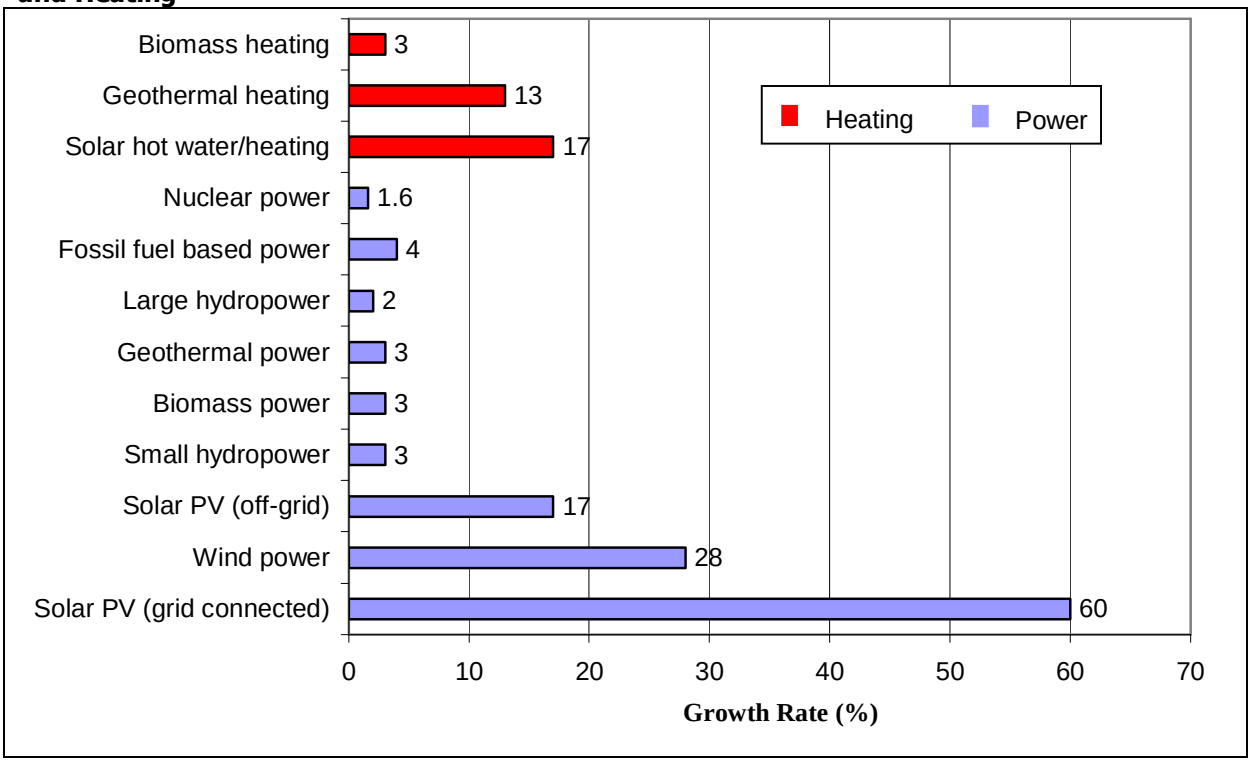
Solar Hot Water/Heating

Solar hot water/heating technologies are becoming widespread, especially in China, Europe, Israel, Turkey and Japan. About 13.5 million square meters of solar thermal collector area was installed in China in 2004, increasing capacity by 26%. Capacity is decreasing in Japan as new installations are falling short of retirements. Almost 40 million households are now using solar hot water technology worldwide. China has the world's largest solar hot water market, with 80% of global additions in 2004.

At least 18 countries besides China (and likely several more) provide capital grants, rebates, or investment tax credits for solar hot water/heating investments. Capital grants are typically 20% to 40% of the system cost. Israel is reported as the only country that mandates solar hot water in new construction through a national level policy (certain high-rise, medical and industrial buildings are exempt).

Many major cities have enacted ordinances requiring solar hot water in new buildings, or are providing incentives for solar hot water investment (Barcelona, Oxford and Portland are examples).

Figure 2.4.2 – Average Worldwide Growth Rates of Renewable Energy Capacity for Power and Heating



Source: REN21, 2005

2.4.4.3 Renewable Energy Adoption and Policy Issues

Capacities in Select Countries

Denmark, Germany and Spain are often cited for their installed, and rapidly growing, renewable electricity generation capacities. While these countries have made large capacity additions with new renewables, their systems are also heavily reliant on conventional sources of energy, such as thermal (fossil fuels), large hydroelectric and nuclear resources. In addition,

these electrical systems are also highly interconnected with their neighbouring transmission grids, providing these systems with the type of resiliency and robustness that would mitigate the interconnection issues typically associated with new renewable generation technologies.

Table 2.4.5, developed by the U.S. EIA, presents a summary of the installed generation capacity and fuel mixes of Denmark, Germany and Spain as compared to Canada. [19]

Table 2.4.5 – Installed Generation Capacity and Fuel Mix of Selected Countries

Country	Canada	Denmark	Germany	Spain
Total Installed Capacity (GW)	112.5	12.7	115.6	50.6
Total Generation (TWh)	566.28	43.32	558.14	247.31
Total Consumption (TWh)	520.9	31.68	510.37	231.19
Total Imports (TWh)	23.582	7.000	45.400	8.7
Total Exports (TWh)	29.320	15.600	54.100	7.500
Thermal (GW)	33.5	10.0	77.4	26.4
Hydro-electric (GW)	67.1	0.01	4.8	12.7
Nuclear (GW)	10.6	0	22.4	7.5
Geothermal, Solar, Wind, and Wood and Waste (GW)	1.4	2.7	10.9	4.0

Source: EIA, 2005

Germany is often cited as a model country for its growth in renewable energies. As the table illustrates, Germany's supply mix is dominated by coal and nuclear resources. While Germany is among the world leaders in installed renewable generation capacity, these resources still represent a minute fraction of Germany's total installed generation capacity.

The information provided in the table is current to the end of 2002, and is the most recent publishing of this comprehensive dataset. Since 2002, the share of renewable energy sources, particularly wind, has changed substantially. For example, Spain is currently the world leader in wind generation, having gone from just over 200 MW of wind capacity in 1997 to over 8,000 MW at the start of 2005.

Investment Flows

About $30 billion was invested in renewable energy capacity and installations in 2004, compared to roughly $110-150 billion invested annually in the power sector worldwide. Investment in renewables over the long term has been addressed in the World Energy Investment Outlook (IEA, 2003). IEA has estimated that one-third of new power generation investment in OECD countries would be in renewable energy over the next 30 years. Increasing numbers of large investors are entering the renewables markets, including investment banks, as the idea that renewable energy represents serious business opportunities is becoming more

[19] EIA (Energy Information Administration), (2005), International Energy Annual 2003 Edition, URL: http://www.eia.doe.gov/emeu/iea/elec.html.

mainstream.

Technology standardization and a growing familiarity and acceptance by financiers at all scales are helping to diversify the sources of renewable energy investments. Commercial banks are beginning to notice renewable energy investment opportunities. Venture capital investors are noticing renewable energy as well, as future projections show solar PV and wind industries growing to $40-50 billion each sometime during 2010-2014. Financing by public banking institutions has helped to stimulate private investments and industry activity, especially in Europe. Multilateral, bilateral and other public financing flows have supported training, policy development, market facilitation, technical assistance, and other non-investment needs in developing countries.

Public investment flows have remained relatively constant over the past few years, however, commitments by several organizations at the Renewables 2004 Conference in Bonn, Germany, suggest the total will increase in the future.

Industry Trends

Direct jobs worldwide from renewable energy manufacturing, operations, and maintenance are believed to have exceeded 1.7 million in 2004 (including some 0.9 million for biofuels production). Indirect jobs are likely several times larger. Even though no estimates exist in the literature for total jobs from renewable energy worldwide, some country-specific estimates are as follows: 130,000 jobs in Germany from all renewables; 250,000 jobs in the China solar hot water industry; 75,000 jobs in the European wind industry; 15,000 jobs in the European solar PV industry; 12,000 jobs in the U.S. solar PV industry; 11,000 jobs in the Nepal biogas industry; 3,400 jobs in Japan from renewables; and 2,200 jobs in the EU for small hydro.

Policy Landscape

The late 1990s and early 2000s saw an emergence of renewable energy policies developed by countries, states, provinces and cities. These policies have had a major impact on the speed and extent of renewable energy development, despite widespread design and implementation problems. Significant market growth has been the result of combinations of policies, rather than single policies, as well as predictable and sustained policy support, local and state/provincial authority involvement, and evolution of individual policy mechanisms through experience.

Policy Targets

A total of 45 countries worldwide have policy targets for renewable energy, while 43 countries have a national target for renewable energy supply. In addition, 18 U.S. states (and the District of Columbia) and 3 Canadian provinces (Nova Scotia, Prince Edward Island and Ontario) have targets based on renewables portfolio standards (RPS). Most national targets are for shares of

electricity production, ranging from 5% to 30%, that typically aim for the 2010 to 2012 timeframe. Canada and the U.S. both lack a national renewable energy target.

Power Generation Promotion Policies

At least 48 countries have a policy or policies to promote renewable power generation (34 developed and transition countries and 14 developing countries), the most common being feed-in laws or tariffs (also known as advanced renewable tariffs or standard offer contracts). Feed-in tariffs have stimulated innovation, interest and investment in renewable power generation in recent years, most notably in Germany, Spain and Denmark.

Renewable portfolio standards (RPS) are expanding in some regions, such as in the U.S. states, Canadian provinces and in India. Several countries have national RPS policies. Australia's RPS requires utility companies to submit a certain number of renewable energy certificates each year, the actual number of which can be adjusted to lead eventually to Australia's national target of 9,500 GWh by 2010. Other national RPS policies have been adopted in the U.K., Sweden, Japan, Thailand and Poland.

Other forms of policy support for renewable power generation include direct capital investment subsidies or rebates, tax incentives or credits, sales tax exemptions, direct production payments or tax credits, green certificate trading, net metering, direct public investment or financing, and public competitive bidding for specified quantities of power generation. At least 30 countries offer some type of direct capital investment subsidy, grant or rebate. At least 32 countries and most U.S. states offer tax incentives and credits for renewable energy.

Green Power Purchasing and Utility Green Pricing

Green power purchasing and utility green pricing programs are increasing due to supportive policies, private initiative, utility programs and government purchases. In 2004 there were over 4.5 million green power consumers in Europe, the United States, Canada, Australia and Japan. Green Power purchasing programs allow consumers to choose to pay a premium for electricity that is produced from renewable sources. Three main vehicles for green power purchases are utility green pricing programs, competitive retail sales by third-party producers (green marketing), and tradable renewable energy certificates. As the markets expand, the price premiums for green power over conventional power have declined. In the U.S. premiums for green power currently range from 1 to 3 cents per. kWh.

In addition to individual consumers, many large companies in the U.S. are voluntarily buying green power products. In Japan, the Japan Natural Energy Company sells green power certificates to commercial and industrial customers, representing 60 GWh over 15 years at premiums of 2.4 to 3.4 cents/kWh.

Municipal-Level Policies

Many local governments are also enacting renewable energy policies, including renewable energy targets, CO_2 emissions reduction goals, solar hot water and solar PV policies, modifications of urban planning methods to incorporate energy consumption, constructing demonstration or pilot projects, in addition to a variety of other policies and programs. Also, many cities have purchased green power for municipal buildings and operations.

Several cities in Australia, South Africa, Germany and California, have adopted future targets of 10% to 20% of electricity from renewables, not only for the municipal government, but for all consumers in the city. The timeframe for such targets ranges from 2010 to 2020.

Municipal CO_2 emissions reduction goals have been set by several cities, such as Freiburg, Germany (25%); Vancouver (6%); and Toronto (20% for municipal government energy). The typical targets range from 10% to 20% below a baseline level (usually 1990), consistent with the Kyoto Protocol targets.

Urban planning that incorporates visions of future clean energy is taking hold as well, with 800 local governments having laid out such visions over the last 10 years. These processes often involve participation from a variety of stakeholders, and many are collaborative efforts among universities, municipal governments, and energy utilities which include research, scenario development, strategic planning, public dialogue and demonstration projects.

2.4.4.5 Conclusion

Renewable energy capacity is becoming an important part of the supply mix in several countries. Renewable energy sources supply 17% of the world's primary energy, from sources including traditional biomass, large hydropower and new renewables (small hydro, modern biomass, wind, solar, geothermal and bio-fuels). New renewables continue to grow rapidly worldwide, most notably solar PV, wind power and solar hot water/heating applications.

2.4.5 CDM Experience in Other Jurisdictions

While many other jurisdictions are pursuing demand-side management and CDM initiatives, Ontario has brought an interesting new development to the exercise. The Minister of Energy, in requesting supply mix advice, has indicated that OPA must determine the possibilities of CDM before considering supply resources. The challenge for OPA has been to find data to provide sound CDM projections. This section examines the developments in some of the leading jurisdictions around the world and in Canada for providing insights for Ontario.

2.4.5.1 Federal Initiatives

Through Natural Resources Canada (NRCan), the Canadian federal government has joined the Energy Star program developed in the United States. The Energy Star program delivers information and applies energy labels to major appliances, heating, cooling and ventilation (HVAC) products, lighting, signage, consumer electronics, office equipment, windows, doors and commercial and industrial products.

The federal government also offers financial incentives to industrial, commercial and residential sectors for efficiency upgrades and retrofits through a variety of programs. These programs include the Industrial Buildings Incentive Program (IBHP), the Canadian Industry Program for Energy Conservation (CIPEC), the Commercial Building Incentive Program (CBIP), the Energy Innovation Initiative (EEI) and EnerGuide for Existing Buildings (EEB) Retrofit. These programs allow applicants to receive up to a certain percentage or up to a predetermined limit of funding back for energy audits or capital upgrades on energy efficiency equipment, upgrades or retrofits.

2.4.5.2 Canadian Provincial Initiatives

Several Canadian electric utilities, including BC Hydro, Manitoba Hydro and Hydro-Quebec, stand out in maintaining an ongoing suite of successful CDM programs. These companies have demonstrated a continued commitment to services and resources that achieve meaningful energy efficiency results.

In 2004, the Canadian Energy Efficiency Alliance prepared a "best practices" assessment of energy company CDM activities. Two programs in particular were highlighted; BC Hydro's Power Smart Traffic Light Program (expected direct energy savings of 26.2 GWh annually) and Manitoba Hydro's Power Smart Commercial Lighting Program (118.5 GWh cumulative, 10.8 GWh in 2003).

BC Hydro, with a current load of approximately 10 GW, operates a number of successful programs under the Power Smart logo, and BC Hydro is slated to invest $690 million over a 10-year period so as to save 3,618 GWh annually.

Power Smart programs offer incentives and services to residential and commercial customers. Residential programs include rebates for turning over inefficient light bulbs, rebates for purchases of Energy Star windows, and the refrigerator buy-back program.

BC Hydro's Power Smart for business programs offer financial incentives for replacing inefficient products with energy efficient technologies, retail sales of energy efficient products, partnerships with large business customers, and financing options for purchases of Power Smart products.

Manitoba Hydro also administers a Power Smart program for homes and businesses, offering loans to homeowners to upgrade insulation, add ventilation, seal air leaks, replace windows and doors, lighting, electrical service and wiring, and upgrading efficiencies of furnaces or water heaters.

The Canadian Energy Efficiency Alliance also went on to credit Enbridge, Union Gas and Hydro-Quebec for their CDM programs.

2.4.5.3 U.S. Federal Programs

CDM programs did not become available across the U.S. until the mid 1980s, but by 1996 there were over 2,300 CDM programs at 600 utilities across the United States.[20] These CDM initiatives have been designed, promoted or encouraged at the federal, state and municipal levels of government. One of the most prominent CDM programs, first developed in the U.S. (and later adopted by Canada), is the Energy Star product labeling initiative.

In 1992, the U.S. Environmental Protection Agency (EPA) introduced "Energy Star" as a voluntary labeling program designed to identify and promote the use of energy efficient products. Since its inception, the EPA has partnered with the U.S. Department of Energy and the Energy Star label can now be found on major appliances, office equipment, lighting, home electronics, and even new homes, commercial and industrial buildings. Energy Star also delivers technical information and tools that allow consumers to make energy efficient choices. It is estimated that Energy Star has saved businesses, organizations and consumers over $9 billion annually.

2.4.5.4 U.S. State Programs

The State of California has one of the longest and most accomplished energy efficiency track records on the continent, with annual spending from $100 million to over $300 million. California's Energy Action Plan identifies energy efficiency and demand response as the State's preferred means of meeting growing energy needs.

Since 1976, total electricity sales have been reduced by 15% relative to what they would otherwise have been, and electricity demand in the state has been held flat. State building codes and appliance efficiency standards account for almost half of the savings. California "Title 24" standards are generally accepted as the most stringent and best enforced energy codes in the United States.

A 2005 staff paper of the California Energy Commission highlighted the economic benefits of the State's CDM programs, relative to the costs of supply options. The report concluded that

[20] Gellings and McMenamin, *DSM in the USA: What's Real, What's Not and How We Can Tell the Difference*, World electricity Conference, London, 1993; Gellings and McMenamin, *Then and Now: The Perspective of the Man Who Coined the Term 'DSM'*, Energy Policy, 24(4), pp. 285-288, 1996.

energy efficiency (EE) program costs (averaging 2.9 cents/kwh for 2000-2004) are more economic relative to base load generation (5.8 cents/ kWh), intermediate generation (11.8 cents/ kWh), and peaking generation (16.7 cents/ kWh).[21]

In the northwest states, the Pacific Northwest Power Planning Council adopted its first power plan in 1983. Since then the region has made significant progress in advancing energy conservation. Cumulative conservation savings together with savings from state codes and federal standards, total about 2,500 MW from 1980-2002, meeting about 10 to 12% of the northwest's electric energy sector needs. Current plans estimate 2,800 MW of cost effective and achievable conservation potential is available in the region by 2025, at a cost less than that of new supply.

2.4.5.5 Republic of Ireland

The Republic of Ireland has a long history of CDM programs, due primarily to its 20 year lack of an interconnection with Northern Ireland (the interconnection was destroyed in 1975). This meant the Republic was wholly dependent on domestic electric generation. Comprehensive CDM programs in the Republic included changes in the electricity price structures, incentives and information programs.

In promoting CDM, the activities included information leaflets in household electricity bills, efficiency improvement advertisements in newspapers and journals, reduced rates for efficiency appliances, and providing information on energy savings on appliances. In addition, schools have provided energy efficiency certification courses and information about energy saving methods. In some cases, energy efficiency devices were mailed to households.

Irish customer information programs have reduced electricity demand by 7%. The republic's response to CDM from 1976 to1993 is the most reliable test case for CDM program evaluation.[22]

2.4.5.6 United Kingdom

In the U.K., residential energy use accounted for about 28% of the primary energy use in 2000 and was predicted to increase over the next decade.[23] In response, the *Home Energy Conservation Act, 1995,* was passed to address global climate change. It aimed to reduce GHG emissions by shifting responsibility for encouraging energy efficiency from the central government to local government authorities. The act targeted improvements of 30% over the next 10 to 15 years for

[21] Rogers, C., M. Messenger and S. Bender (Rogers et al.), 2005. *Funding and Savings For Energy Efficiency Programs for Program Years 2000 through 2004.* Staff Paper, California energy Commission, July 2005, CEC-400-2005-042.
[22] Dulleck, U. and S. Kaufmann (2004*). Do Customer Information Programs Reduce Household Electricity Demand? – The Irish Program.* Energy Policy, 32, pp. 1025-1032.
[23] Jones, E., M. Leach, and J. Wade (Jones *et al*.), 2000. *Local Policies for DSM: The UK's Home Energy Conservation Act,* Energy Policy, 28, pp. 201-211.

residential energy efficiency. A report in 1999, however, estimated an improvement of only 2% over the first two years of the Act.[24]

On the labelling front, the U.K., bound under European Union legislation, made energy labelling mandatory between 1995 and 1999 for cold appliances, washing machines, dryers and dishwashers. Energy labelling was intended to encourage the purchase of more efficient modules and transfer knowledge regarding energy consumption to the consumer. In mid 1999, however, price liberalization led to a price reduction for fuels in the UK, which made consumers less interested in energy efficiency.

2.4.5.7 Conclusion

CDM programs are an integral part of electric system planning and policy in many jurisdictions worldwide. CDM programs have been praised for their ability to reduce or reshape demand loads, direct and indirect economic benefits and for mitigation of environmental impacts. OPA is learning from the experiences (success stories and failures) in other jurisdictions in order to further its mandate for creating a conservation culture in Ontario.

2.4.6 Environmental Assessment Approaches and Results

SENES Consultants has developed an approach for OPA to evaluate environmental effects arising from alternative generating technologies. It did this by reviewing a number of international and two Canadian Integrated Resource Planning (IRP) documents. These documents were chosen because they were held to be leading IRP processes and potentially reflective of current objectives for OPA's supply mix advice. Each document was reviewed to determine what considerations, if any, were given regarding impacts to the natural environment. The following is a summary of how other jurisdictions considered impacts on the natural environment in determining their generation mix, based on SENES's recommendations.[25]

In general, a standardized approach to incorporating environmental concerns in the context of electricity IRP does not exist. Some jurisdictions address the environment in a qualitative fashion, while others focus on the potential impact of future carbon pricing, while still others do not address environmental consequences in any significant fashion.

2.4.6.1 Puget Sound Energy – Least Cost Plan April 2005

Puget Sound's plan looked at electrical needs and supply options without investigating the requirements of specific supply option implementation. Environmental considerations focus on

[24] Ibid.

[25] This section is based on the SENES report, *Methods to Assess the Impacts on the Natural Environment of Generation Options*, September 2005. See Part 4.4 for the full report.

air emissions - specifically CO_2. A few relevant points drawn from this consideration of carbon emissions are:

- Current Washington law taxes new generation on the basis of the expected future CO_2 output
- The economic analysis finds that the inclusion of CO_2 tonnage costs made natural gas competitive with coal
- The largest cost risk associated with coal plants is viewed as potential carbon and greenhouse gas emission restrictions and costs; and
- In its economic analysis, PSE used $5/tonne beginning in 2010 and increasing by 5%/year as the cost of CO_2 emissions, based on the recommendation of the National Commission on Energy Policy.

Again, demand side management has been incorporated in the analysis.

This plan provides useful information regarding carbon emission costing in the U.S., including through the application of taxes.

2.4.6.2 Utah PacifiCorp – 2004 Integrated Resource Plan

The Utah PacifiCorp IRP provides the framework for future actions to provide reliable, least cost service with manageable and reasonable risk to its customers. It also provides an analytical approach for the integration of new resource alternatives with existing generation and transmission assets and an approach to analyze results and determine the Preferred Portfolio. For Integrated Gasification Combined Cycle (IGCC), its environmental impacts are discussed in terms of air emissions (NOx, SO_2, Hg), ground and surface water, land use, aesthetics, waste management, fuel mining, road transportation and storage. However, IGCC is the only generation option accorded this level of specific analysis. General statements concerning impacts are made for other energy generation options, with a focus on air emissions, but no analysis is given with respect to environmental impacts. The IRP did include the associated costs of emissions in its comparison of portfolios.

2.4.6.3 State of California – Draft Energy Action Plan II

California's IRP indicates the "overarching goal is for California's energy to be adequate, affordable, technologically advanced, and environmentally sound." The plan, however, does not provide any guidance regarding how environmental concerns will be implemented, with the exception of the inclusion of renewable energy sources in supply mix options. Aspects that could be seen as environmental include a brief review of renewable energy options and a need to decrease climate change emissions.

Nevertheless, the plan contains action items with respect to efficiency improvement and demand side management initiatives.

2.4.6.4 Idaho Power – 2004 Integrated Resource Plan

Idaho Power's recent IRP includes no monetization of environmental considerations. It does include brief recognition of "social costs," of which environmental costs are considered a part. Further, in evaluating potential supply options, qualitative environmental advantages and disadvantages are identified.

Energy efficiency and demand response programs are quantified with respect to expected savings. These programs are seen as a way of reducing peak demand requirements.

This document provides a concise but comprehensive review of the advantages and disadvantages of different supply options, as well as provision of carbon emission costing.

2.4.6.5 Hawaiian Electric Company Inc. – Draft IRP 2006-2025

Within Hawaiian Electric's recent IRP, the utility and the commissions are concerned primarily with efficiency, reliability, costs, and meeting electricity needs. However, the public consultation conducted as part of the plan revealed that the public was primarily concerned with environmental protection, societal impacts and the utilization of sustainable energy resources. Despite this public concern, the plan contained very little on environmental aspects. There is brief mention of qualitative impacts for marine and terrestrial environment and quantitative impacts for air emissions. The analysis of air emissions included an assessment of potential future changes to legislative requirements.

Significant effort is expended in the plan to discuss and analyze demand side management options, initiatives and potential cost/benefits of each program.

2.4.6.6 BC Hydro 2005 Resource Options Report

One of the more relevant portions of BC Hydro's IRP is the section on environmental and social attributes. Two key concepts relevant to the supply mix advice are found in this report:

- Developing environmental attributes that can assist in decision-making requires finding a balance between what is easy to measure and what is meaningful to the decision-makers; and
- The role of stakeholder input into the process of creating decision criteria is critical; the measurement of stressors is relatively objective, but choosing what to measure, what units to use and how to use these in making decisions depends on stakeholders' values.

BC Hydro proposed the following environmental attributes for analysis:

- Land Impacts - measured as land impacted by structures (footprint of the generating facility, roads, transmission lines, pipelines and inundated area)
- Water Impacts - hydro developments were measured based upon areas subject to dewater effects, area subject to backwater effects, footprint of facilities, fish presence, areas affected by stream crossings, and aquatic habitat effects; and
- Air Impacts - measures included oxides of nitrogen, oxides of sulphur, fine particulates, mercury, volatile organic compounds and greenhouse gases.

2.4.6.7 PEI's Energy Framework & Renewable Energy Strategy

The current energy mix in Prince Edward Island includes 80% from imported petroleum based production, 13% imported oil-fired production, 6.5% from biomass-based production, and 0.5% from on-island wind power. Ideally, the province would like to satisfy provincial demand for energy with wind power and hydrogen fuel technology within 10 years.

This long-term strategy requires the appropriate mix of conventional and renewable sources. The Renewable Portfolio Standard (RPS) defines the percentage of energy that will be assessed by a jurisdiction from renewable sources. However, there is nothing in the strategy pertaining to evaluation methodology or identification of environmental impacts from generation options.[26]

2.4.6.8 U.K. Electricity Supply Strategy

Much like Ontario, the U.K.'s electricity supply largely depends on an infrastructure laid down in the 1940s to the 1960s. Also like Ontario, the changing resource base and the challenge of climate change require a fundamental adaptation and renewal of both network and infrastructure.

The Council for Science and Technology's report recommends that government consider incentives that will increase the level of research and development investment and training by the industry. Investment by government in research and development should be targeted towards the development of new and renewable fuel sources, energy management and intelligent networks.

The strategy also highlights the need for large-scale non-carbon electricity generators in order to meet CO_2 targets in 2020. As the strategy points out, wind power alone will not achieve this goal. Suitable technologies suggested include nuclear and tidal generation.

Current regulatory structures in the UK have an impact on energy options and the market. The paper encourages the funding of renewable and low-carbon energy initiatives in the U.K.

[26] Ibid, pp 2-1 to 2-6.

Overall, this document, although not specifically providing an analysis framework, does suggest increased use of renewable and low carbon technologies and stresses the importance of an appropriate supply mix.

2.4.6.9 Electricité de France's (EDF) Energy Supply Mix

EDF's report focused on energy generation and its environmental cost in the current supply mix. As with other documents, the primary focus was on the greenhouse gas emissions. This document provides an environmental overview of each of the generation sources in EDF's energy mix and demonstrates the actions taken by EDF to limit the environmental impacts. In 2001, EDF's generation mix in France consisted of 84.2% nuclear, 12.4% hydroelectric and 3.4% thermal generation. Therefore, in 2001, 96.6 % of the electricity generated in France did not result in emissions of greenhouse gases.

This document does not provide a framework analysis for environmental impacts. However, it does highlight the associated environmental impacts based on the energy mix.

2.4.7 Conclusion on Other Jurisdictions for Ontario

Based on this review of other jurisdictions, the evidence suggests that current energy policy in Ontario is well on its way to becoming a leading jurisdiction in the use of integrated resource planning, including the role of renewables and conservation and demand management and the analysis of environmental impacts.

In bringing back IRP to Ontario, the uniqueness of the new framework is that it is based on a hybrid of planning and competitive markets. The framework is more challenging than in past, when a vertically integrated public monopoly both ran the industry and did the IRP, but the path has been made easier by planning the IRP within a planning agency, OPA.

The supply mix advice, which is a precursor to the IPSP, places Ontario with the leading jurisdictions because it establishes targets for CDM and renewables, both of which must be set before conventional supply options can be established.

Ontario's new planning framework is also notable because it emphasizes sustainability. The commitment of OPA is to set Ontario on a path of sustainability and not to let planning urgency interfere with the proper assessment of sustainability.

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2.5 What are the Challenges?

Planning for Ontario's electricity supply mix is a challenging task which must take into account a variety of drivers and constraints. In this section, OPA identifies the challenges and considerations that helped shape the development of advice to the Minister of Energy.

2.5.1 Key Findings

- Ontario's supply mix is being shaped by replacement of coal-fired generation, retirement of nuclear units, and growing electricity demand
- Current demand and consumption trends will lead to a large resource gap that will need to be met by conservation and new or refurbished generation capacity, most of which will need to be base-load power
- CDM can reduce requirements to increase supply, but the exact potential for energy efficiency improvements is uncertain in terms of technical (feasible), economic and achievable (cost effective) potential
- OPA received two estimates of CDM potential beyond what is assumed in the load forecast across four differing energy efficiency scenarios that reflect increasingly aggressive levels of conservation
- OPA's estimates on CDM contributions to reducing peak demand on an average summer day cover a wide range and can adapt to the effectiveness of CDM programs
- Key uncertainties for supply mix include unpredictability of future natural gas prices and availability, impacts of transitioning to supply resources currently existing only in small amounts or not at all, and uncertainty regarding future policy choices and social values and behaviours that influence conservation
- Some uncertainty regarding the supply mix is relieved through current procurement processes for new generation and demand-side resources
- OPA has included potential environmental impacts of the supply mix and environmental attributes of several generation portfolios
- OPA has compared portfolios in terms of both absolute impacts and environmental loading scores; the latter normalize different environmental impacts using a common scale for comparison; each portfolio is compared on the basis of its environmental loading score

2.5.2 Introduction

One of the first challenges to be addressed is the size and nature of the need for electricity in Ontario. Over the next 20 years, up to 24,000 MW of generation will have to be conserved, built or refurbished in Ontario. OPA's planning activities are driven by:

- Expected future demand for electricity in the province and the potential for conservation and demand management (CDM)
- Several key transitions and uncertainties that will unfold during the next two decades
- Maintaining the real-time operability and stability of the electricity system as it evolves
- Meeting Ontario's electricity needs in an environmentally responsible manner

2.5.3 Ontario's Resource Gap

Ontario's installed generation capacity currently totals approximately 30,662 MW. As outlined in Table 2.5.1, 11,397 MW of this capacity is nuclear, 7,756 MW is hydroelectric, 6,434 MW is coal-fired, 4,976 MW is gas and/or oil-fired, and 99 MW is an aggregate of other resource types.

Table 2.5.1 – Ontario's Current Operable Generation Capacity

Resource	Existing Operable Capacity (MW)
Nuclear	11,397
Hydroelectric	7,756
Coal	6,434
Gas/Oil	4,976
Other	99
Total	**30,622**

Source: OPA

Ontario's future power and energy requirements will be acutely shaped by two factors in the near- and medium-terms. Firstly, all of Ontario's coal-fired capacity will be replaced by early 2009. Secondly, it is estimated that 95% of Ontario's existing nuclear capacity will reach retirement age between 2013 and 2025.

The implication of these two factors is dramatic. Within the next 20 years, Ontario stands to lose up to 17,316 MW of generation capacity, almost 60% of the current total, due to coal replacement and nuclear retirement. Most of this will be base-load capacity.

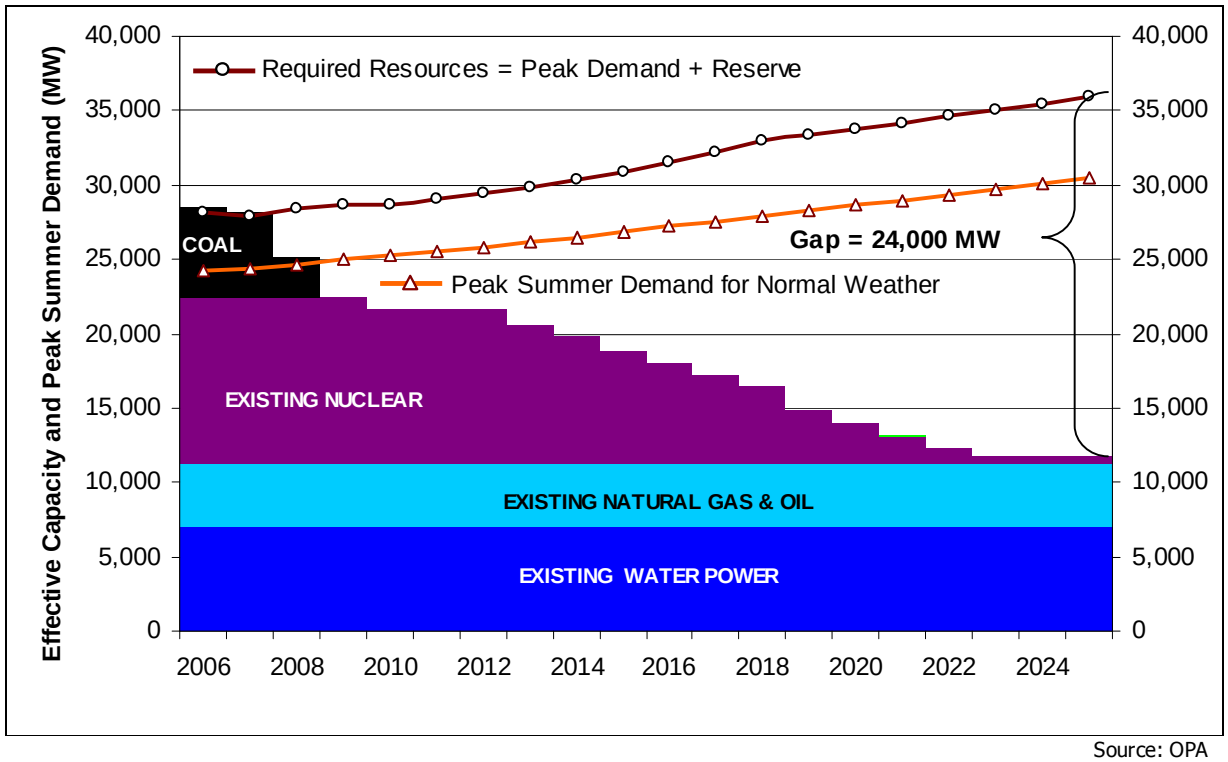
In the meantime, Ontario's demand for electricity is growing, albeit at a historically low rate. If current consumption and demand trends continue, Ontario's total resource requirement -- the amount required to meet peak demand plus reserve requirements and losses -- will reach nearly 36,000 MW by 2025. This represents an increase of approximately 8,000 MW from today's requirement.

Declining capacity availability and a rising capacity requirement result in a potential resource gap of approximately 24,000 MW by 2025. The resource gap reflects the difference between

resource requirements (36,000 MW) and available resources (12,000 MW).

Figure 2.5.1 illustrates two significant assumptions with respect to the gap. Firsly, it depicts a total available capacity of 12,000 MW in 2025. This assumes all of Ontario's coal-fired capacity is removed from service and that 15 of today's 16 existing nuclear units are retired, while no new resource additions, including conservation measures, are put in place. Secondly, it assumes that all existing capacity, other than coal and nuclear, is maintained throughout the 20-year horizon.

Figure 2.5.1 – Illustrative Total Ontario Generation Capacity 2005 – 2025: Coal Retirement, Nuclear Retirement, Continued Load Growth, No New Resource Additions



Source: OPA

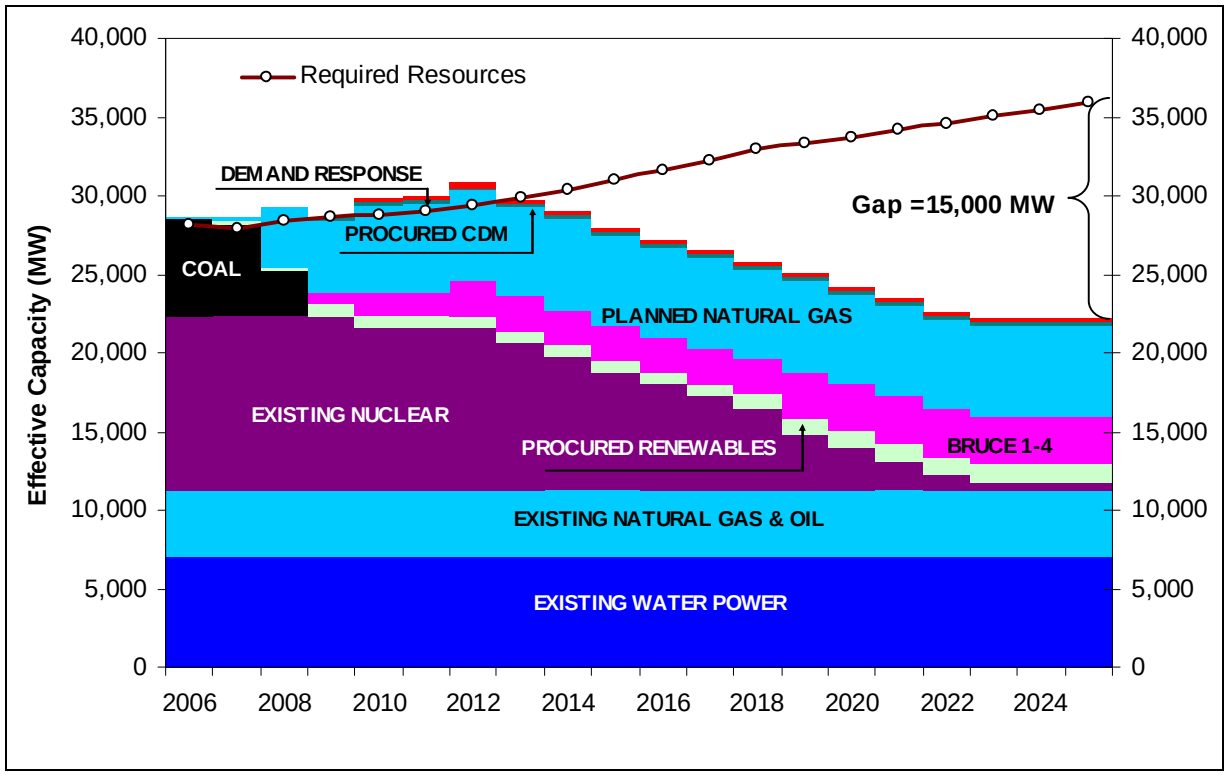
The Ontario government has initiated a series of procurements for new electricity supply and CDM. As outlined in greater detail below, the procurements – should they all materialize – would deliver approximately 9,500 MW of nominal capacity by 2010, including the restart of the Bruce nuclear units 1 and 2.

For planning purposes, this nominal resource total is derated, partly on account of the 10% capacity contribution assigned to wind power. Wind is expected to form a sizeable part of the total procured capacity. Wind contribution is derated to reflect the portion of "nameplate" wind capacity that can be relied upon during periods of peak demand. In effective terms, the procurements would add well over 8,000 MW to Ontario's supply base.

The procurements initiated by the government, including the restart of Bruce units 1 and 2, as

well as the later refurbishment of Bruce units 3 and 4 would decrease the size of Ontario's potential resource gap in 2025 compared to the scenario outlined above. As illustrated in Figure 2.5.2, the gap in this case would be reduced to approximately 15,000 MW.

Figure 2.5.2 – Illustrative Total Ontario Generation Capacity 2005 – 2025: Coal Replacement, Nuclear Retirement, Continued Load Growth, Additions of Procurements and Bruce 1 & 2



Source: OPA

The replacement of Ontario's coal-fired generation and the retirement of its nuclear units raises two key challenges. The first is with respect to ensuring immediate, near-term, and future resource adequacy. The second is with respect to ensuring a reasonable response capability of Ontario's integrated power system. For the future system to be operable, it must have an appropriate mix of base-load and peaking/intermediate resources, which need to be appropriately utilized and balanced.[1]

The supply mix must balance these resource capabilities to serve different requirements -- very few resources can "do it all". It is, for this reason, that a mix of resource types is required. Ontario's replacement of coal-fired generation will soon eliminate a large portion of its peaking/intermediate capability. In the medium-term, Ontario faces the loss of a large portion of its base-load capability through nuclear retirement.

[1] For a more detailed discussion of base-load, peaking/intermediate resources, see Part 2.7.

As illustrated in the preceding figures, the immediate and near term form a critical and challenging transition period, as Ontario's coal-fired plants are replaced. In the mid and long terms, the resource outlook will be largely shaped by the precipitous loss of the majority of Ontario's base-load capacity.

2.5.4 CDM Uncertainty

2.5.4.1 Potential

In order to assess the size of Ontario's electricity gap, OPA had to determine both the size of expected demand and how much this demand could be reduced through CDM measures. As discussed below, the estimates of CDM potential are very uncertain in terms of how much can be obtained, and how much these efforts are likely to cost.[2]

CDM refers to a range of activities designed to influence the use of electricity by consumers. CDM activities fall into three categories:

- Conservation activities that result in less electricity being used than would normally be the case.
- Energy efficiency activities that result in less electricity being used to provide the same level of service.
- Load management activities such as shifting electricity use to different times or the interruption of use so as to reduce demand at peak times.

CDM is a valuable resource. In reducing growth in demand, the requirement to build new supply facilities is also reduced. The potential for energy efficiency improvements can be defined in terms of technical, economic and achievable potential:

- *Technical potential:* The extent of savings that could be realized if energy efficiency measures were applied in all technically feasible instances, regardless of cost or consumers' preferences.
- *Economic potential:* The subset of technical potential which is cost-effective.
- *Achievable potential:* The subset of economic potential that can reasonably be expected to develop as the result of specific policies and programs.

Cogeneration, another mean of reducing customer demand, is included in this report as a supply option rather than as conservation.

[2] For a discussion of the load forecast methodology, see Part 2.6.

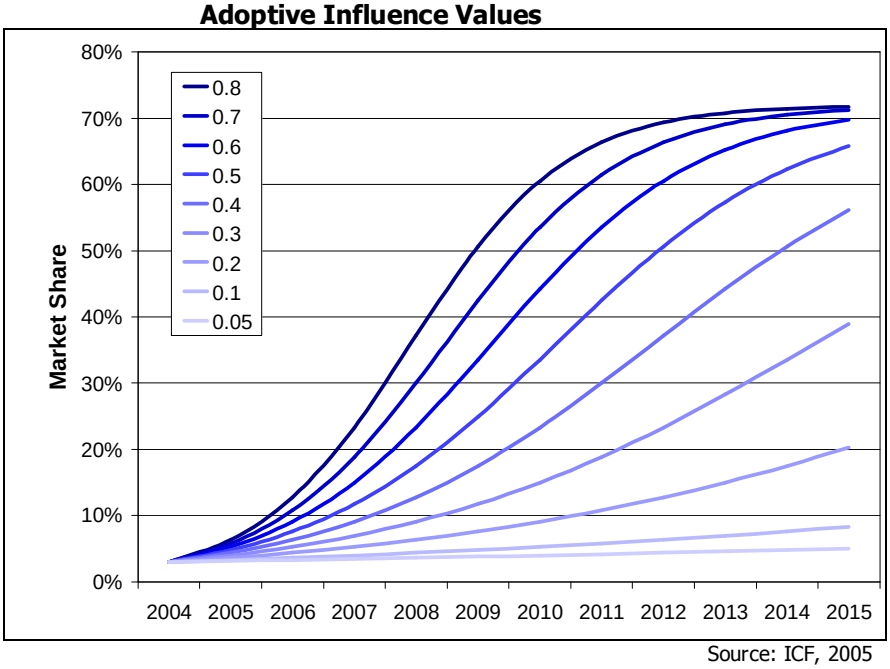
Achievable potential is less than economic potential because not all measures, even when cost-effective, are acted upon. Financial constraints and competing priorities can reduce the actual uptake on a measure. Incentives can be used to improve the capital payback time and increase buyer interest in the investment. Intrinsically, achievable potential is a function of consumer behaviour. Since such behaviour cannot be predicted perfectly, estimates of achievable potential are inherently uncertain.

Achievable potential can be estimated using the "adoptive influence parameter", illustrated as the S-shaped curves in Figure 2.5.3. Adoptive influence parameters range from 0 to 1, with higher numbers denoting steeper, more pronounced S-shaped curves. The curves model growth in market share for energy efficiency measures, technologies or improvements over time. Higher adoptive influence parameters mean faster diffusion, growth and leveling off of efficiency measures in the market. In other words, market share increases for any CDM measure as more people choose energy efficiency over standard efficiency equipment and processes.

2.5.4.2 CDM Estimation

Market share data confirm that the adoptive influence can be significantly higher for CDM measures affected by targeted programs than for measures not directly influenced by program interventions. In estimating CDM potential across a range of scenarios in the supply mix project, an adoptive influence parameter (A) of 0.5 was assumed for the EE 50 scenario and 0.75 was assumed for the EE 100 scenario.

Figure 2.5.3 – Projected Market Adoption Under a Range of Adoptive Influence Values



Source: ICF, 2005

The present exercise considers the amount of conservation savings from new policies and programs. These savings are additional to those referred to as "technology improvement" - energy efficiency improvements that would occur naturally, without such new policies and programs. These technology improvement savings result, for example, from end of life turnover of vintage stock (such as refrigerators and air conditioners) and their replacement with currently available, improved equipment. Such improved equipment will have arisen from a combination of possible factors, including new efficiency standards introduced previously or simply market forces, such as suppliers that compete on the basis of offering higher efficiency equipment. The adoption of higher efficiency equipment may also be a response to historical efficiency programs that, for example, provided information on the benefits of choosing higher efficiency products.

Technology improvement is captured in OPA's base demand forecast. OPA adopted the forecast in IESO's 10-year Outlook as its base demand forecast, but, this forecast did not make explicit assumptions regarding the extent of technology improvement present. Since the methodology used to produce the IESO forecast is heavily influenced by past trends and behaviours, it is reasonable to assume that technology improvement is incorporated implicitly. It is difficult, however, to quantify its contribution.

The OPA is in the initial stages of developing its internal capability to incorporate CDM impacts into its long-term planning. In the interim, OPA contracted with ICF Consulting to assess electricity efficiency potential in Ontario on the supply mix advice.

To accomplish this task, ICF developed a methodology based on a combination of two complementary approaches. The first "experience-based" approach was based on a review of other efficiency potential analyses as well as actual program impacts in other jurisdictions, and was included in order to assist in benchmarking expectations.

The second "accounting approach" provided a "bottom-up" assessment of what sectors, sub-sectors and end-uses could potentially contribute to efficiency improvements.

The combination of both approaches helps to take advantage of the strengths of each. At the same time, however, each approach has weaknesses. In terms of the experience-based approach, the applicability of even high quality U.S. data to Ontario cannot be assumed. A successful accounting assessment relies heavily on the availability of an up-to-date, accurate representation of current stock and current decision-making regarding uptake of energy-efficient equipment – a condition which, unfortunately, is not currently met in Ontario. That is, the quality of the Ontario-specific data is also not sufficient to give a high level of confidence. Using a hybrid accounting-experience approach, ICF produced an achievable energy efficiency potential estimation for OPA on August 26, 2005 (estimate # 1).[3]

[3] ICF Consulting, *Assessment of Energy Efficiency Potential: 2006-2025, Version 1*, August 25, 2005.

As mentioned above, CDM forecasts are known to be uncertain, in part due to methodological and data constraints. In light of this, ICF decided that a second estimation should be made in order to verify the robustness of the August 26 results. Different assumptions, particularly with respect to the appropriate magnitude of technology improvement, produced a second estimate that was significantly different than the first. The second achievable energy efficiency potential estimate was delivered by ICF on October 7, 2005.[4]

Neither estimate on its own produced results that ICF or OPA felt confident could be used as a definitive estimate of energy efficiency potential. Given the uncertainty of the data, OPA adopted the first energy efficiency estimate, believing this was the prudent course. The reasoning is that the August ICF results are more consistent with estimations that ICF has produced for utilities in other jurisdictions.

Despite these qualifications, OPA has found the estimation exercise undertaken by ICF to be very informative and beneficial in identifying the nature of data limitations. It also points to what OPA can do to further build its capability in this area.

2.5.4.3 Energy Efficiency

In carrying out the detailed (stock-based) accounting component of the hybrid approach used for both estimations, ICF considered four scenarios reflecting increasingly aggressive levels of intervention.

- *Energy Efficiency (EE) 25:* Attempts to mimic program intervention that is largely information based, with financial incentives set to 25% of incremental cost of new equipment installation.
- *EE 50:* Reflects a common program approach wherein financial incentives are set to 50% of incremental costs, along with more intensive marketing.
- *EE 100:* Financial incentives are set to 100% of equipment incremental cost and program delivery and administration costs are higher, reflecting the more intensive technical assistance required for this level of program.
- *EE 100 plus aggressive standards:* A simulation representing a broad range of aggressive generic standards. When a standard is implemented, it is assumed that the minimum efficiency equipment that can be bought is in the high efficiency category.

ICF produced point estimates of technical and economic potential using 2004 load, i.e. estimates for technical potential are 8,200 MW (37 TWh), and estimates for economic potential are 5,200 MW (30 TWh).

[4] ICF Consulting, *Assessment of Energy Efficiency Potential: 2006-2025, Version 2*, October 7, 2005.

Tables 2.5.2 and 2.5.3 illustrate data for a hot summer day. Efficiency improvements in end use that are weather sensitive, like air conditioning, will provide additional savings with above normal weather. Table 2.5.9 is provided at the end of Part 2.5.4 to give savings in terms of normal weather as well as for a hot summer day.

Table 2.5.2 – Range of Achievable Energy Efficiency Peak Demand Savings (MW) (on an extreme hot day)

Scenario		2010		2015		2020		2025	
		Est. 1	Est. 2	Est. 1	Est. 2	Est. 1	Est. 2	Est. 1	Est. 2
Technology Improvement *	MW	4660	1250	7060	2470	8530	3940	9630	5410
	%	16	5	21	8	23	12	24	15
EE 25	MW	440	200	600	950	780	1840	980	2280
	%	1.8	0.8	2.3	3.6	2.8	6.5	3.3	7.6
EE 50	MW	1110	850	1530	3050	1680	4040	1490	4330
	%	4.5	3.4	5.8	11.5	6	14.3	5	14.4
EE 100	MW	1790	1770	2040	4290	1820	4800	1570	4520
	%	7.2	7.1	7.7	16.2	6.5	17	5.2	15.1
EE 100 Plus Standards	MW	2440	4620	2360	5380	1960	5050	1710	4730
	%	9.8	18.6	8.9	20.4	7	17.9	5.7	15.8

*Efficiency improvement embedded in Base Forecast and which is expected to occur without the additional impact of new programs or policies.

Source: ICF

Table 2.5.3 – Range of Achievable Energy Efficiency Energy Savings (TWh)

Scenario		2010		2015		2020		2025	
		Est. 1	Est. 2	Est. 1	Est. 2	Est. 1	Est. 2	Est. 1	Est. 2
Technology Improvement*	TWh	32	5.4	47.3	10.7	57.4	18.1	65.2	27.1
	%	20.7	3.5	28.4	6.4	31.7	10	32.9	13.7
EE 25	TWh	3.2	1.1	4.5	5.7	5.3	12.7	5.3	17.2
	%	2.1	0.7	2.9	3.7	3.3	7.8	3.1	10.1
EE 50	TWh	8.2	5	10	20.4	8.9	27.2	6.9	27.7
	%	5.5	3.3	6.4	13.1	5.4	16.7	4	16.2
EE 100	TWh	12.2	10.9	11.9	28.3	9.3	30.4	7.1	28.2
	%	8.2	7.3	7.6	18.2	5.7	18.7	4.2	16.5
EE 100 Plus Standards	TWh	15.1	27.2	12.5	32.1	9.6	30.8	7.3	28.5
	%	10.1	18.2	8	20.6	5.9	18.9	4.3	16.7

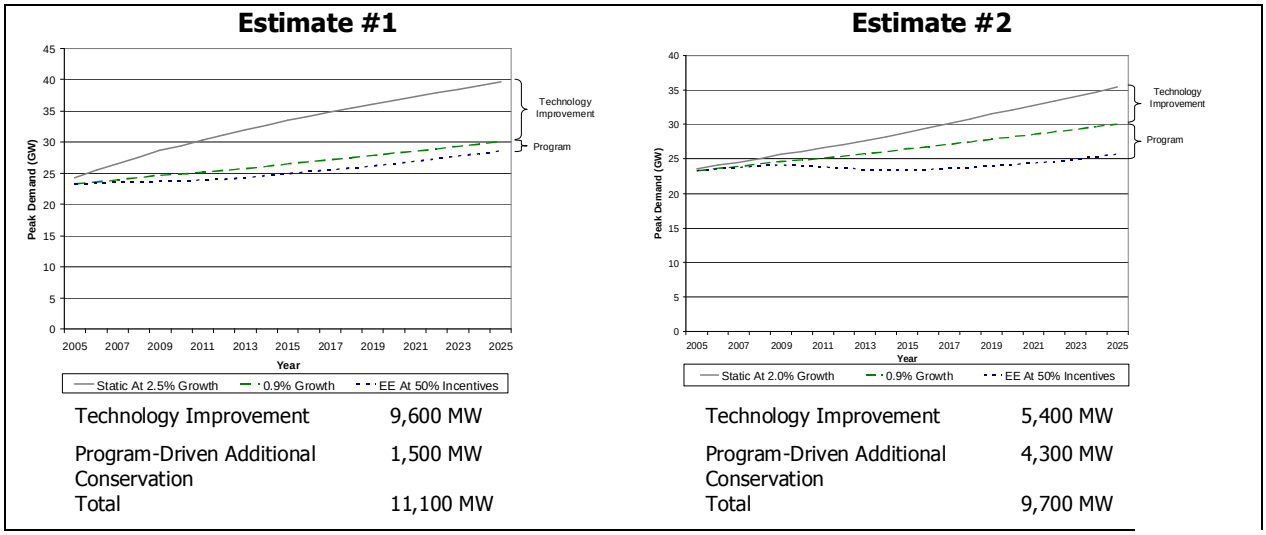
*Efficiency improvement embedded in Base Forecast and which is expected to occur without the additional impact of new programs or policies.

Source: ICF

EE 50 is in line with programs in other jurisdictions that have maintained a sustained commitment to conservation. Estimates 1 and 2 in 2020 range from 6 to 14.3% in peak and 5.4 to 16.7% in energy. Figures 2.5.4 and 2.5.5 show the two accounting assessments of technology improvement and achievable potential at the EE 50 level. The figures illustrate that total savings, namely, the sum of technology improvement and EE program impacts, are approximately the same for both accounting assessments (about 65 TWh, 10,000 MW). The difference lies in the extent of technology improvement savings that are assumed to be embedded in OPA's Base Forecast.

Figures 2.5.6 to 2.5.9 give the estimated range of achievable efficiency potential for energy by sector and end-use, in the year 2020.

Figure 2.5.4 – Technology Improvement & Program Impacts – Peak

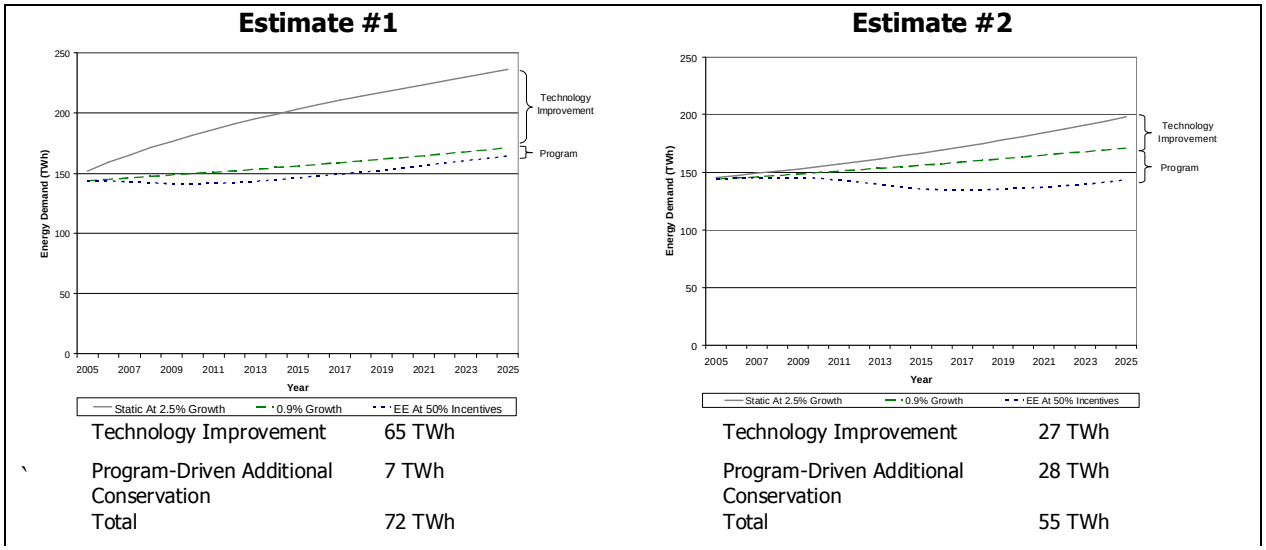


Technology Improvement	9,600 MW
Program-Driven Additional Conservation	1,500 MW
Total	11,100 MW

Technology Improvement	5,400 MW
Program-Driven Additional Conservation	4,300 MW
Total	9,700 MW

Source: ICF

Figure 2.5.5 – Technology Improvement & Program Impacts – Energy

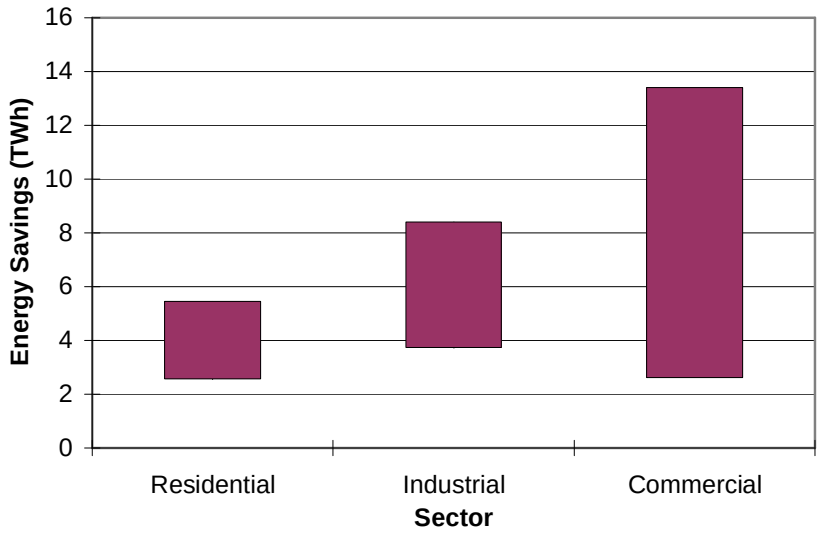


Technology Improvement	65 TWh
Program-Driven Additional Conservation	7 TWh
Total	72 TWh

Technology Improvement	27 TWh
Program-Driven Additional Conservation	28 TWh
Total	55 TWh

Source: ICF

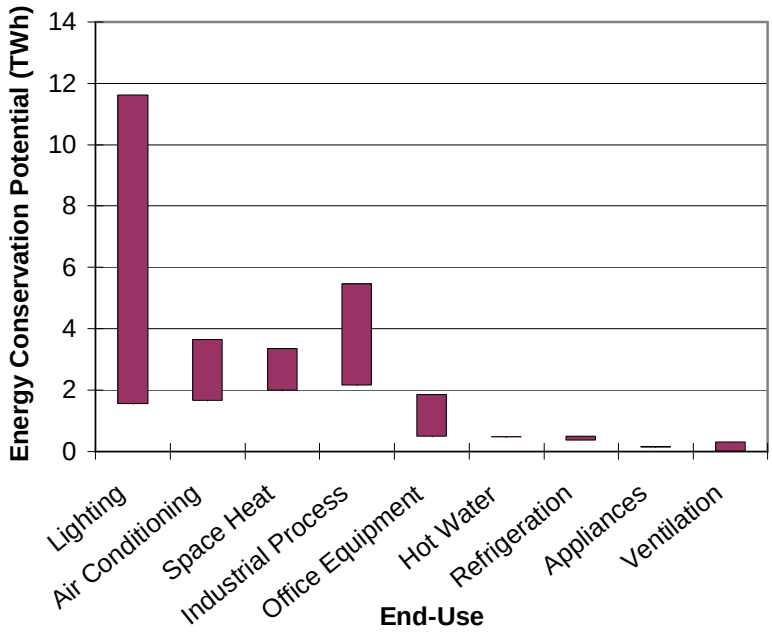
Figure 2.5.6 – Range of Achievable Energy Efficiency Potential by Sector – 2020 (TWh)



Sector	Savings (TWh)
Residential	2.6 – 5.5
Industrial	3.7 – 8.4
Commercial	2.6 – 13.4
Total	8.9 – 27.2
	5.4% – 16.7%

Source: ICF

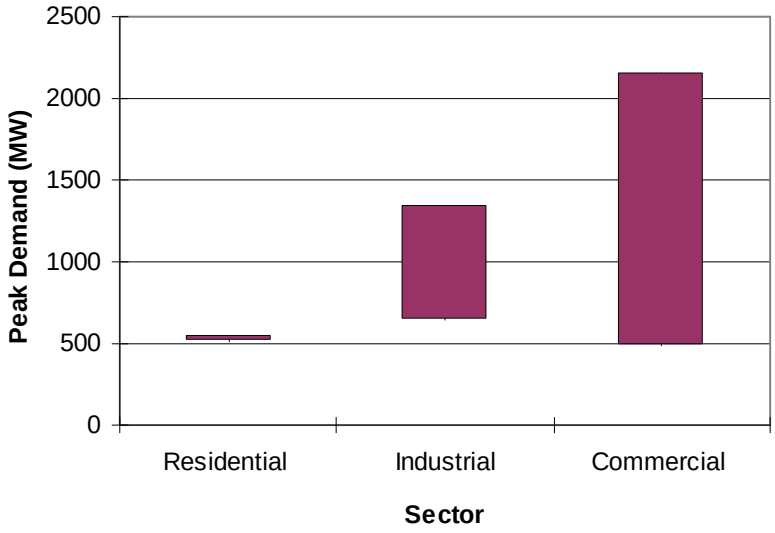
Figure 2.5.7 – Range of Achievable Energy Efficiency Potential by End Use – 2020 (TWh)



End Use	Savings (TWh)
Lighting	1.6 – 11.6
Air Conditioning	1.6 – 3.6
Space Heat	2.0 – 3.3
Industrial Process	2.2 – 5.5
Office Equipment	0.5 – 1.8
Hot Water	0.5 – 0.5
Refrigeration	0.4 – 0.5
Appliances	0.1 – 0.2
Ventilation	0.01 – 0.3
Total	8.9 – 27.2
	5.4% – 16.7%

Source: ICF

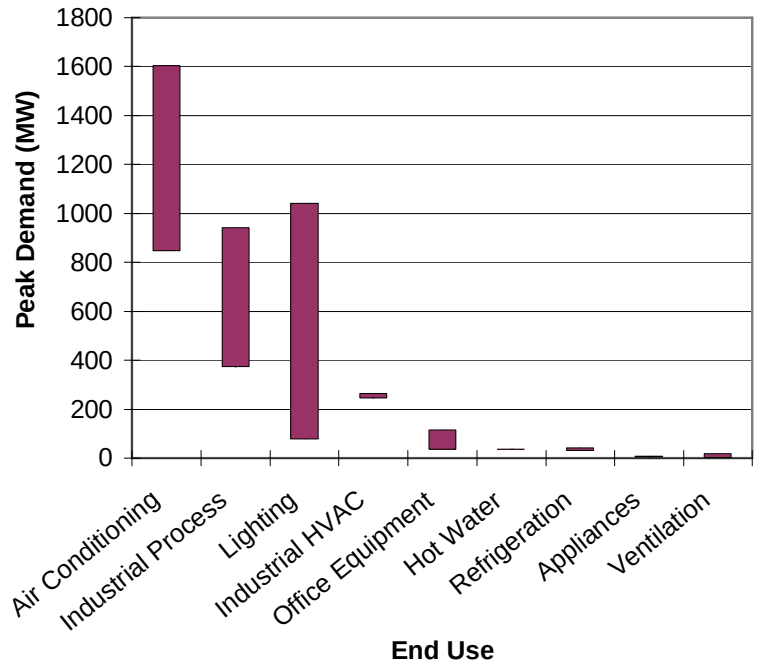
Figure 2.5.8 – Range of Achievable Peak Demand Efficiency Potential by Sector – 2020 (MW)



Sector	Savings (MW)
Residential	540 – 550
Industrial	640 – 1,340
Commercial	490 – 2,150
Total	1,680 – 4,040
	5.9% – 14.3%

Source: ICF

Figure 2.5.9 – Range of Achievable Peak Demand Efficiency Potential by End-use – 2020 (MW)



End Use	Savings (MW)
Air Conditioning	850 – 1,600
Industrial Process	370 – 940
Lighting	80 – 1,040
Industrial HVAC	240 – 260
Office Equipment	40 – 110
Hot Water	30 – 40
Refrigeration	30 – 40
Appliances	3 – 6
Ventilation	1 – 20
Total	1,680 – 4,040
	5.9% – 14.3%

Source: ICF

In terms of energy, the commercial and industrial sectors are seen to be the key areas of efficiency potential. The main contributors are lighting, air conditioning, space-heating and industrial processing. Since Ontario is now a summer peaking system, space-heating savings are not considered in terms of peak impact. That is, air conditioning, lighting, and industrial processing are seen as the major areas of achievable peak savings.[5]

Table 2.5.4 gives the breakdown of commercial potential savings on a business type basis. The major contribution of offices is evident. Offices are estimated to account for 65% of the savings in the commercial sector, in terms of both energy and peak.

Table 2.5.4 – Range of Commercial Sector Achievable Energy Efficiency Potential by Business Type – 2020

Energy (GWh)	
Building Type	**Savings (GWh)**
Educational Services	80 – 480
Arts, Entertainment and Recreation	70 – 130
Information & Cultural Industries	10 – 120
Accommodation & Food Services	310 – 1,250
Health Care & Social Assistance	150 – 880
Wholesale Trade	50 – 380
Offices	1,810 – 9,030
Retail Trade	100 – 880
Transportation & Warehousing	8 – 150
Other Services	20 – 90
Total	**2,609 – 13,390**
	3.9% - 9.9%

Peak (MW)	
Building Type	**Savings (MW)**
Educational Services	20 – 70
Arts, Entertainment and Recreation	10 – 20
Information & Cultural Industries	2 – 15
Accommodation & Food Services	85 – 295
Health Care & Social Assistance	25 – 110
Wholesale Trade	10 – 60
Offices	310 – 1380
Retail Trade	20 – 145
Transportation & Warehousing	4 – 35
Other Services	4 – 20
Total	**490 –2150**
	4.8% - 8.9%

Source: ICF

[5] Details regarding breakdowns by sector and end-use can be found in Part 4.2.

In order to benchmark the potential estimates for Ontario, ICF gathered program impact data from three sources: Pacific Northwest utilities, Energy Information Administration (pertaining to total US utility energy efficiency investment) and the State of California. All three sources have long-standing conservation experience.

The magnitude of Ontario's projected energy efficiency potential will depend on jurisdictions Ontario's programs are assumed most likely to mirror. If Ontario's programs unfold similarly to those identified by the EIA, energy savings will be less than if the province's programs unfold similarly to those in California or the Pacific Northwest.

The Pacific Northwest and California are jurisdictions that have experienced sustained commitment to conservation initiatives over a 20-year period. The State of California has one of the longest and most accomplished energy efficiency track records on the continent, with annual spending from $100 million to over $300 million. Since 1976, total electricity sales have been reduced by 15% relative to what would otherwise have been. State building codes and appliance efficiency standards account for almost half of the savings. In the Northwest, cumulative conservation savings, as well as state codes and federal standards, have reduced electricity needs by 12% over a similar period. The lower savings from the EIA show the impact of more sporadic funding.

Costs for these programs can be difficult to assess. The costs used in these estimations and shown in the following table are felt to be indicative of the costs that would be incurred for these types of programs. Individual circumstances may vary. Levelized costs of $39 - $53 per MWh (5% discount rate) and $51 – $68 per MWh (11% discount rate) are in line with similar estimations for programs in other jurisdictions. The levelized costs in the following table consider total incremental costs, both incentive and participant as well as typical marketing and administration costs. A discount rate of 5% (real) is representative of a social rate whereas 11% is more in line with a commercial rate.

The savings estimates are based on assumptions of continual, consistent investment in energy efficiency over a 20-year period.

Table 2.5.5 – Costs for Higher Levels of Energy Efficiency

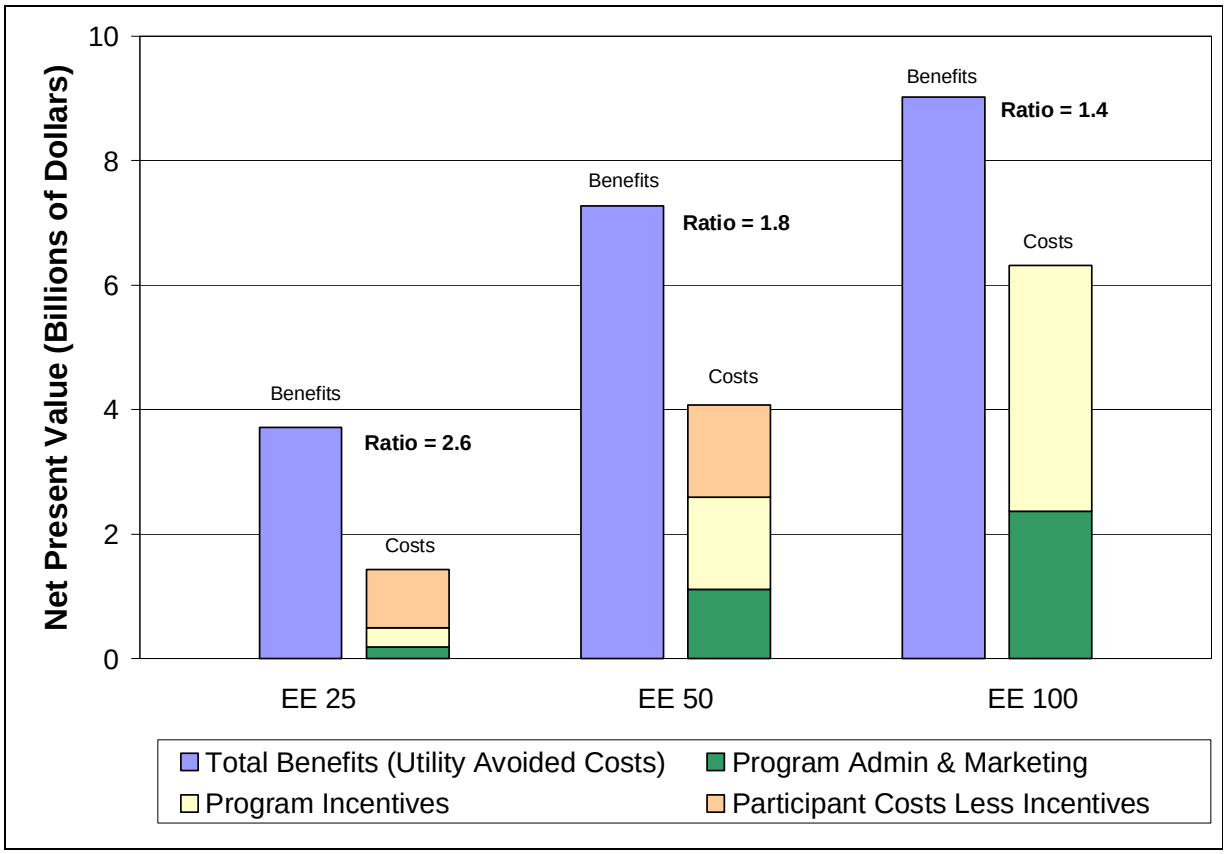
Program Intensity	Estimate 1*				Estimate 2				LUEC ($/MWh)	
	Savings in 2025		PV Cost ($B)		Savings in 2025		PV Costs ($B)			
	MW	GWh	5%	11%	MW	GWh	5%	11%	5%	11%
EE 25	980	5,300	1.06	0.65	2,280	17,200	2.33	1.43	39	51
EE 50	1,490	6,900	2.63	1.85	4,330	27,700	5.79	4.07	44	57
EE 100	1,570	7,100	3.77	2.87	4,520	28,200	8.30	6.31	53	68

*Costs for Estimate 1 were produced by OPA based on values provided by ICF for Estimate 2.

Source: OPA

Another way of viewing the costs is on a cost/benefit basis, as shown in Figure 2.5.10. Benefits are given in terms of value of utility avoided costs.

Figure 2.5.10 – Benefits and Costs for Energy Efficiency Programs



Source: Produced by OPA based on values provided by ICF.

Figure 2.5.10 shows that the most favourable benefit/cost ratio is obtained at lower incentive levels. Diminishing returns are obtained when doubling incentives from 50% to 100%.

2.5.4.4 Demand Response

In addition to energy efficiency measures, demand response measures will have further impacts on Ontario peak demand. Demand response is defined as load response either called for by others or as a price response by end-use customers. Measures include direct load control, partial load reduction or complete interruption. Price response could be due to real-time pricing and time-of-use rates.

Customers will vary in their interest and ability to respond to demand response measures. During periods of high prices, demand response is capable of lowering overall costs for all customers, not just for those providing the demand response.

There are some basic systems that must be in place to facilitate demand response. At a minimum, there is a need for: interval meters, communication of metered data, communication of prices and the ability of the consumer to intervene and produce the required response.

The OPA, in its consideration of demand response, essentially followed the approach of the IESO. The IESO, in its 10-Year Outlook, includes in its reliability analysis only demand reduction under contract. The reasoning is that dispatchable demand, when not under a contract obligation, can quickly change to non-dispatchable.[6]

Table 2.5.6 lists the level of demand response OPA has assumed in its supply mix analysis. The Minister of Energy has directed OPA to procure 250 MW or more of demand side management and/or demand response initiatives.

Table 2.5.6 – Level of Demand Response

Source	MW
Ministry of Energy RFP	250
Loblaws Properties	10
Smart meters	500

Source: OPA

In addition to energy efficiency impacts, a "smart meter" program proposed for Ontario will have further impacts on Ontario's peak demand. Navigant Consulting was requested to provide an estimate of potential peak savings arising from the implementation of these meters.

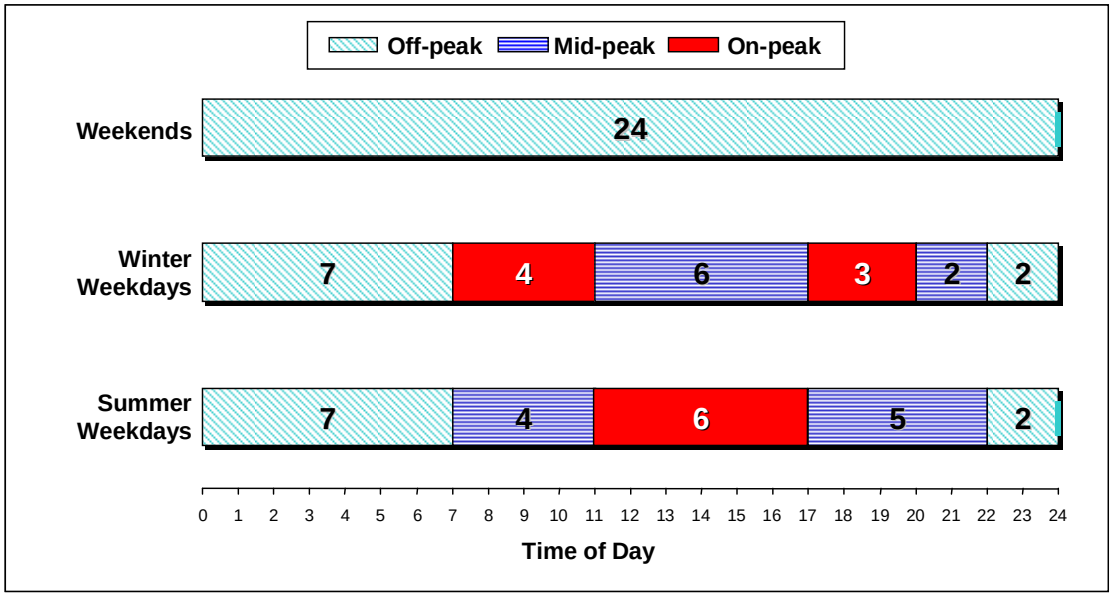
The Government of Ontario has established a target for the installation of smart meters for all Ontario customers by December 31, 2010, with an interim target of 800,000 smart meters installed by 2007.

In contrast to the conventional metering currently used for most residential and small commercial customers in Ontario, smart meters are able to track consumption in hourly (or finer) intervals and report this information to a central data warehouse. The use of Time-of-Use (TOU) and Critical Peak Pricing (CPP)[7] enables load shifting, demand response and conservation. The Regulated Price Plan consumption, where the residential and small commercial customers are situated, accounts for a little over 40% of annual consumption.

The TOU price structure was assumed to be that given in the Ontario Energy Board's Regulated Price Plan Manual (March 11, 2005) as shown in Figure 2.5.11 below:

[6] Dispatchable demand is load that market participants may shed in response to price signals or directions.
[7] CPP is too preliminary in its definition by the OEB and is not addressed in this analysis.

Figure 2.5.11 – Time Periods for Time-of-Use Price Signals

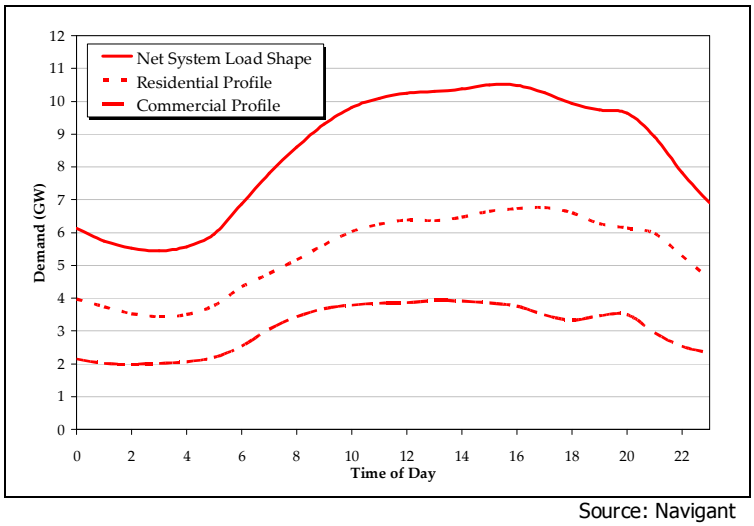


Source: OEB

The TOU prices for the initial RPP period, starting on April 1, 2005, are related to each other in approximately a 1 / 2 / 3 ratio. That is, mid-peak prices are approximately double the off-peak prices and on-peak prices are approximately triple the off-peak prices. We used this same 1 / 2 / 3 price ratio in our analysis.

The typical July weekday profiles used by Navigant in its smart meter analysis are shown in Figure 2.5.12 below:

Figure 2.5.12 – Typical July Weekday Load Profiles

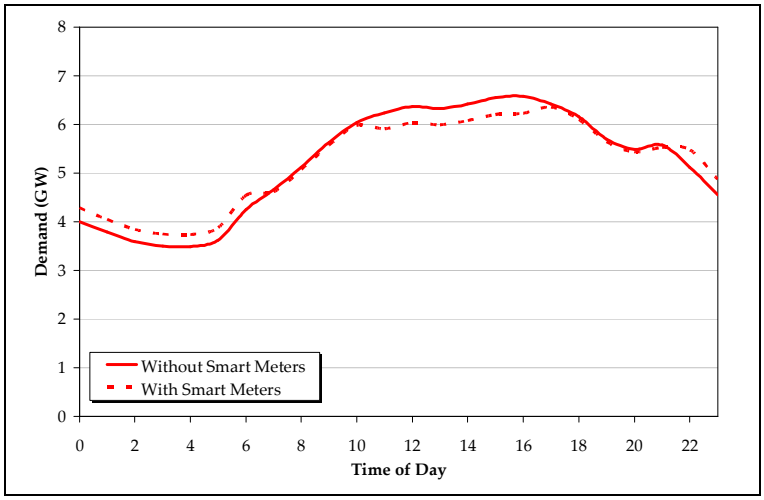

Net System Load Shape
Residential Profile
Commercial Profile
Demand (GW)
0 1 2 3 4 5 6 7 8 9 10 11 12
0 2 4 6 8 10 12 14 16 18 20 22
Time of Day

Source: Navigant

Most of the affected load will derive from the residential sector.

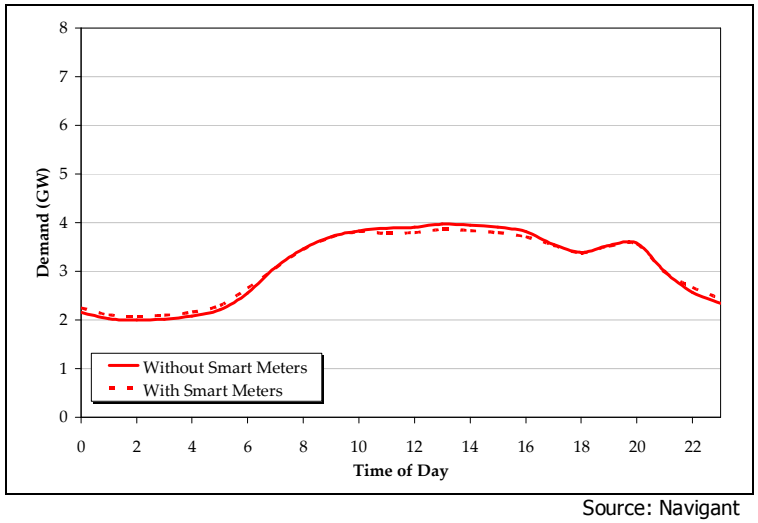
Figures 2.5.13 and 2.5.14 show the July residential and commercial profiles with and without smart meters and TOU rates.

Figure 2.5.13 – July Residential Load Profile With and Without Smart Meters and TOU Rates



Source: Navigant

Figure 2.5.14 – July Commercial Profile with and without Smart Meters and TOU Rates



Source: Navigant

Table 2.5.7 below gives the annual impact of smart meters on Ontario load. The savings assume that a smart meter program is offered in conjunction with a EE 50 efficiency program. The impact of smart meters will be lower in the presence of more aggressive efficiency programs

because the adoption of a more efficient piece of equipment will lower the savings and, therefore, the attractiveness of load shifting.

Table 2.5.7 – Smart Meter Impact on Ontario Load

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Smart meter impact (MW)	16	44	88	163	218	276	322	354	373	376
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Smart meter impact (MW)	424	479	483	487	492	497	501	506	512	517

Source: Navigant

2.5.4.5 Conservation Summary

Table 2.5.8 summarizes the estimated conservation contribution to reducing peak demand.

Table 2.5.8 – Conservation Estimates Assuming OPA Base Forecast*

	Impact (MW)	
Program	**Hot Summer Day**	**Normal Summer Day**
Energy Efficiency`	1,500-4,300	1,040 – 3,600
Smart Meter	500**	500
Demand Response	260**	260

Notes:* Based on OPA Base forecast. ** Underestimated for a hot summer day

Source: OPA

Additional aggressive standards in the next 20 years could be expected to reduce demand further. No detailed estimation was carried out and therefore such further reductions have not been included.

Significant fuel switching, especially for residential space and water-heating, occurred in the last two decades, but has tapered off. The tapering off has occurred because remaining homes are less accessible to gas. In addition, recently increasing gas prices have made switching less attractive.

Peak and energy savings can be specified in a number of ways, including actual day, normal weather day and extreme weather day. Naturally, end uses that are weather sensitive, like air conditioning, will be affected by variation in weather. Efficiency measures that decrease weather sensitive usage will have greater impact the more extreme the weather.

To reflect this, the energy efficiency potential estimates are provided both for impact on an average normal summer day and on a hot summer day.

The values provided by ICF Consulting, which appear in Part 4.2 and Section 2.5.4., are for a hot summer day. In parts of the study, the analysis is more appropriately carried out on a normal weather basis. The following table provides energy efficiency impacts on both a weather-normal and hot summer day basis.

Table 2.5.9 – Energy Efficiency Impacts on Load (MW) on a Normal Weather and Hot Summer Day Basis

	2006		2007		2008		2009		2010	
	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2
Hot summer day	166	31	434	111	726	262	948	505	1,113	847
Normal summer day	216	32	443	117	622	204	884	398	917	587

	2011		2012		2013		2014		2015	
	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2
Hot summer day	1,241	1,278	1,443	1,762	1,486	2,244	1,485	2,661	1,531	3,053
Normal summer day	995	903	1,090	1,276	1,118	1,691	1,100	2,037	1,199	2,471

	2016		2017		2018		2019		2020	
	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2
Hot summer day	1,576	3,346	1,632	3,499	1,678	3,703	1,696	3,856	1,680	4,037
Normal summer day	1,252	2,821	1,260	3,060	1,264	3,229	1,256	3,332	1,227	3,453

	2021		2022		2023		2024		2025	
	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2	Est 1	Est 2
Hot summer day	1,655	4,181	1,625	4,279	1,580	4,334	1,538	4,347	1,487	4,326
Normal summer day	1,194	3,537	1,162	3,591	1,124	3,614	1,086	3,605	1,041	3,572

Source: ICF, Navigant

2.5.5 Key Future Transitions and Uncertainties

In addition to uncertainty related to CDM, Ontario faces a series of unprecedented transitions and uncertainties over the next 20 years. Some of these are immediate, while others will occur in the longer term. Some are discrete, while others will be ongoing. All have influenced the planning considerations and approach to preparing OPA's supply mix advice.

In the short term, Ontario will replace 6,434 MW of coal-fired capacity by early 2009. Ontario has relied on coal-fired generation since the mid-20th century for versatile and fast-ramping service. The successful replacement of this capacity with cleaner generation resources within a short period will form a sizeable challenge and will require a supportive and coordinated policy approach, for example, with respect to land use and environmental planning and approvals.

During the same period of time, Ontario will see a more than doubling of its natural gas-fired generation capacity, such that, by 2010 gas-fired generation will represent nearly one third of the province's total installed generation. In face of uncertainty concerning future natural gas prices and volatility, increased reliance on natural gas in the power sector will require strategies for mitigating Ontario's exposure to gas price risk.
Ontario's existing nuclear units are aging. Between 2013 and 2025, 15 of the province's nuclear units, representing 10,882 MW of capacity, will reach retirement or "end of service" age. This scale of base-load capacity turnover is unprecedented in Ontario's history. Approximately 32% of existing capacity will reach retirement age within the next decade. The retirement, refurbishment or replacement of Ontario's aging nuclear fleet will require long and predictable lead-times as well as coordination on refurbishment outages, transmission and system integration, permitting and approvals, and procurement of materials and labour.

Throughout the course of the study period, Ontario will see additions of generation resources that either exist in relatively small amounts today, or which are not yet a part of Ontario's supply mix. Wind, biomass, fuel cells, photovoltaics, inter-provincial purchases, and coal gasification are examples. In addition, Ontario will see numerous incremental additions of small hydroelectric resources. The degree to which each of these resources will contribute towards Ontario's overall mix is not yet fixed. It will necessarily be influenced by social values, policy choices, and economic and technical factors.

Conservation will form a significant component of Ontario's supply mix. As discussed previously, a wide range of estimates exist as to how much Ontario can conserve throughout the study period. The extent to which Ontario can achieve high levels of conservation will be largely influenced by policy choices and social values and behaviours. Accordingly, uncertainty exists as to the degree to which the various estimated conservation potentials will materialize.

Ontario's supply mix will need to include the flexibility to adapt to actual conservation achievements, both in instances where actual achievements are higher or lower than expected. Flexibility will be supported by early identification of the policies necessary for addressing a variety of possible outcomes, investing now to shorten lead-times for options that are likely to be required, and preserving flexibility to make decisions at a later time.

2.5.5.1 Coal Replacement and Transition

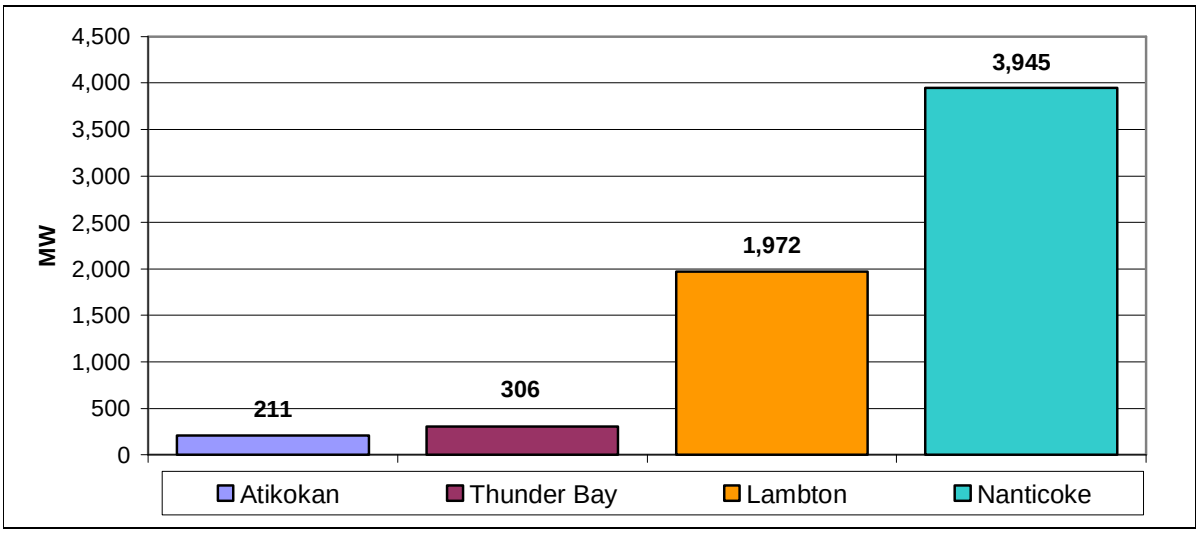
There are currently 15 coal-fired units in Ontario, totalling approximately 6,434 MW, or 21% of the province's total installed generation. The Ontario government has committed to replace all of the province's coal capacity by 2009 as replacement resources become available. In its latest 10-year Outlook (July 2005), the IESO noted that "this transition represents the largest and most significant electricity system change ever undertaken in Ontario".

The timely replacement of Ontario's coal-fired units will be essential, yet challenging and, in

particular, will require substantial effort to ensure that resource adequacy and transmission system security is maintained.

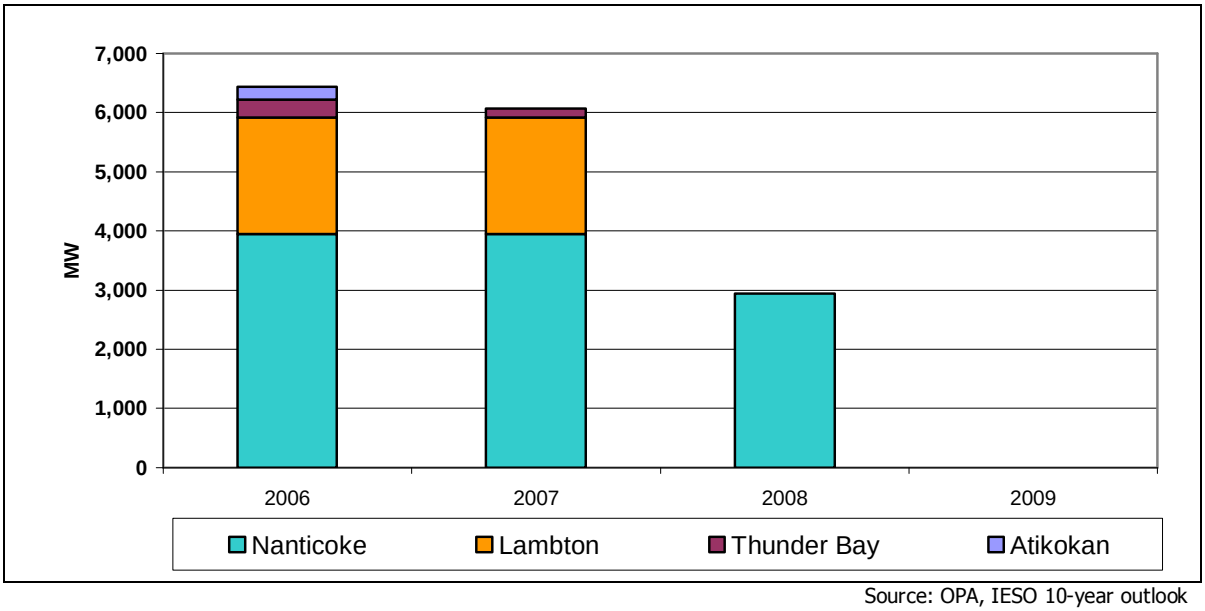
Coal-fired generation is a flexible resource. It offers a range of base-load and peaking/ intermediate capability. Particular attention will be required to ensure Ontario's power system continues to have an appropriate balance of these capabilities as replacement resources are introduced.

Figure 2.5.15 – Capacity of Ontario's Existing Coal-Fired Fleet



Source: OPA

Figure 2.5.16 – Coal Replacement Schedule



Source: OPA, IESO 10-year outlook

2.5.5.2 Procurement Initiatives

As part of its efforts to replace Ontario's coal-fired fleet, as well as in view of meeting its renewable energy and conservation targets, the Government of Ontario has established a number of requests for proposals for new generation and demand-side resources. The total nominal capacity of these procurements, as outlined below, would provide for approximately 9,500 MW by 2010. Coordination will be required to ensure the oncoming resources are successfully brought on-line and on schedule, including coordination among agencies responsible for power system planning, operations, and land use and environmental planning and approvals. As emphasized in the IESO's latest 10-year outlook, the successful implementation of the procurements will be highly critical over the coming years.

Table 2.5.10 – Current Procurement Initiatives

Procurement		Nominal MW by 2010
1	CES RFP	1,992
2	RES I	395
3	RES II	975
4	RES III	200
5	West GTA	1000
6	Downtown Toronto	600
7	Cogeneration	1,000
8	DSM + DR	250
9	Thunder Bay Replacement	310
10	York Region	200
11	Goreway Station	894
12	Bruce 1-2, Bruce 3-4 will add another 1,500 MW beyond 2010	1,500
13	Low Income & Social Housing CDM	100
14	Lighting/Appliance CDM	100

Source: OPA, Ministry of Energy, IESO

Of the 9,500 MW of resources expected to come on-line by 2010 as a result of the current procurement initiatives, nearly 6,000 MW will be natural gas-fired. By 2010, Ontario's natural gas-fired generation capacity is expected to total nearly 11,000 MW.

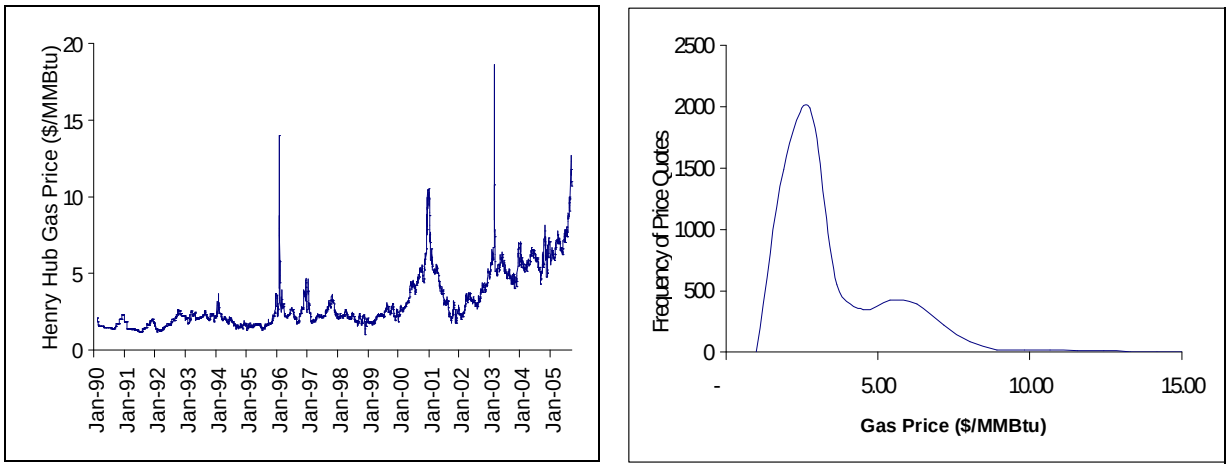
Increasing reliance on gas-fired generation will result in Ontarians having increased exposure to changes in natural gas prices and volatility. This result will require approaches to mitigate this

exposure, for example, through energy conservation, prudent use of natural gas as a fuel source, resource diversification and through other hedging strategies. In addition, ongoing efforts will be required to ensure Ontario's gas storage, transport, and delivery infrastructure can incorporate the expected increases in Ontario's demand for natural gas. The Ontario Energy Board has already taken initiative in this regard.

The precise extent to which gas prices will rise or fall in the future is unknown, although they will be affected by supply-side factors such as the maturation of North American natural gas resource base, the availability of new areas for natural gas development, and the advent of LNG (Liquefied Natural Gas). LNG, while expensive and controversial to site, dampens prices because it brings in imports. Demand-side factors will include population and economic growth, technological choices and advancements, intensity of gas consumption across all sectors, and environmental policies and impacts on fuel choices.

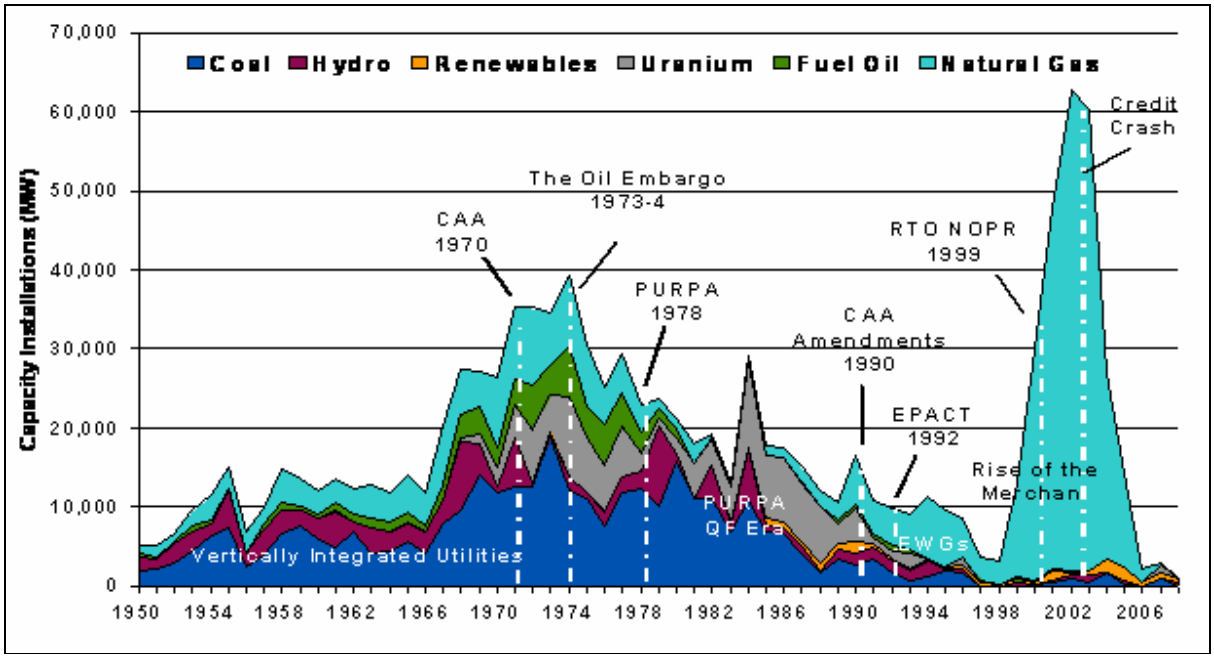
As illustrated in Figure 2.5.17, natural gas prices have been on an upward trend over the past 5 years. Figure 2.5.18 outlines the marked growth in natural gas-fired generation capacity in the U.S. over the past decade. This boom has stimulated awareness of gas price risk across the continent and has intensified interest in fuel diversification in the power sector.

Figure 2.5.17 – Historic Natural Gas Prices (Henry Hub, Nominal $US/MMBtu)



Source: Navigant

Figure 2.5.18 – Gas-Fired Generation Capacity Additions (U.S.)



Source: Global Energy Decisions

2.5.5.3 Nuclear Retirement, Refurbishment and Replacement

In total, 20 nuclear units were placed into service in Ontario between 1971 and 1992. Sixteen of these units are currently in operation, totalling 11,397 MW of capacity, or 37% of Ontario's total installed capacity.

Table 2.5.11 – Nuclear Capacity in Ontario

Site	Facility	# of Operable Units	# of Units Out of Service	Total Operable Capacity (MW)	Total Out of Service Capacity
Pickering	Pickering A	2	2	1,030	1,030
	Pickering B	4	0	2,064	0
Clarington	Darlington	4	0	3,524	0
Kincardine	Bruce A	2	2	1,540	1,540
	Bruce B	4	0	3,239	0
TOTAL		**16**	**4**	**11,397**	**2,570**

Source: OPA

Table 2.5.12 – Original In-Service Dates of Ontario's Nuclear Fleet

Facility	In-Service	Age at 2010
Pickering A	1971-1973	37-39
Pickering B	1983-1985	25-27
Darlington	1989-1992	18-21

Source: OPA

The expected service life of a nuclear unit could be as long as 60 years but only if there is refurbishment at about 30 years. Without refurbishment, it is estimated that almost all of Ontario's existing nuclear units will reach retirement age between 2013 and 2025. While it is difficult to predict the precise end-of-service date for each unit, it is estimated that 32% of Ontario's existing nuclear capacity will reach retirement age (without refurbishment) within the next 10 years. Approximately another 63% will reach retirement age within between 2015 and 2025.

Table 2.5.13 – Retirement Eligibility Schedule of Ontario's Nuclear Fleet

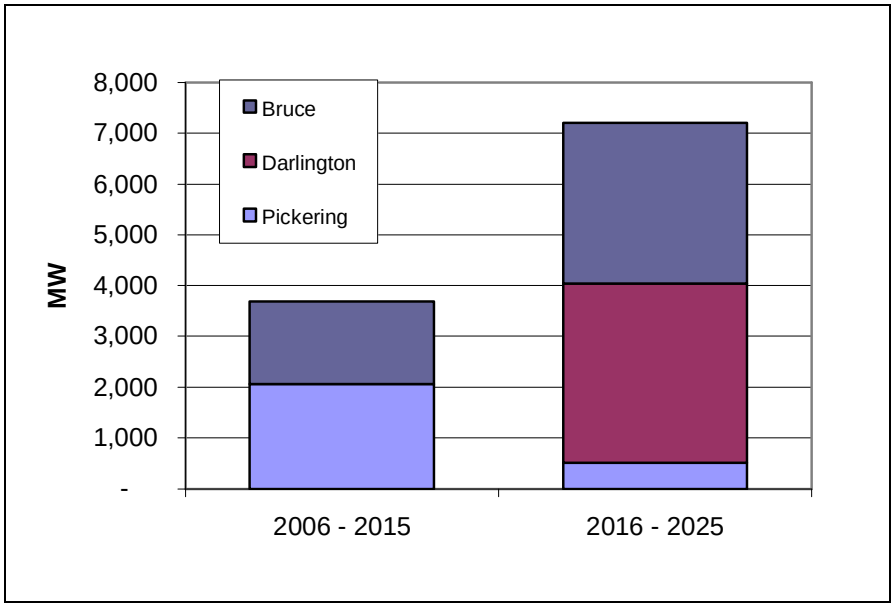
	Time Period		
	2006 - 2015	**2016 - 2025**	**Total: 2006 - 2025**
Number of Units	6	9	15
Installed Capacity (MW)	3,682	7,200	10,882
Percentage of 2006 Installed Capacity	32	63	95

Source: OPA, Nuclear Operators

Figure 2.5.19 and Table 2.5.13 illustrate estimated eligible capacity retirements by facility between 2006 and 2025. Figure 2.5.20 illustrates estimated reductions in Ontario's nuclear capacity across the entire existing fleet due to retirement. This is not accounting for any possible refurbishment or replacement or the anticipated addition of Bruce units 1 and 2 in 2009 – 2010.

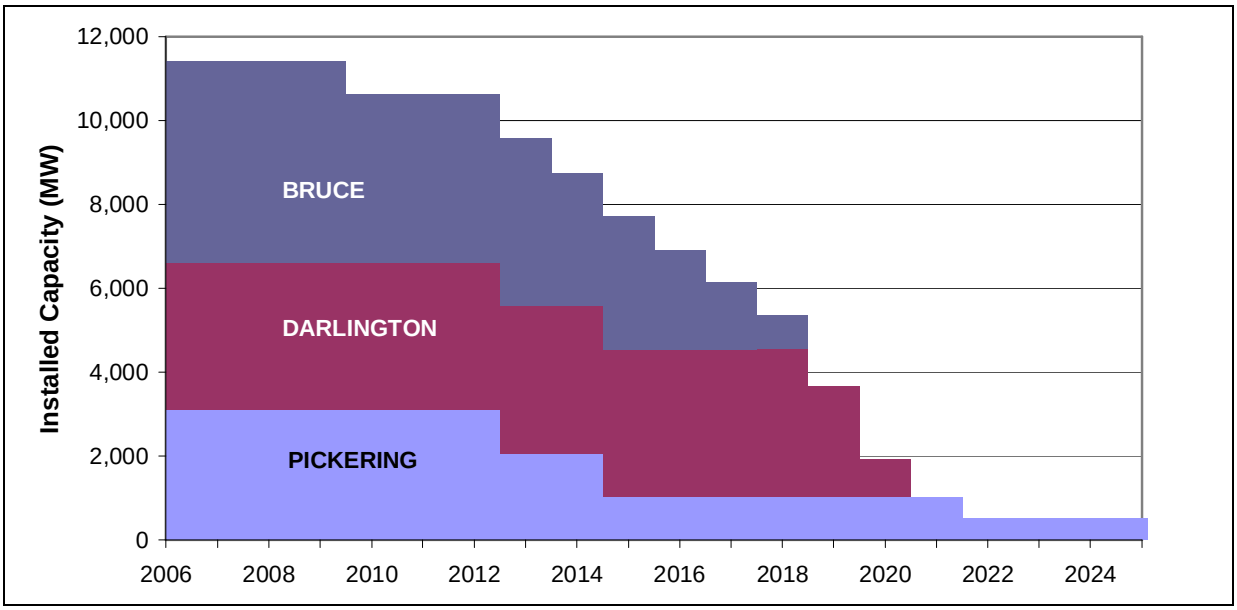
Assumptions around these estimates represent a major planning uncertainty. Actual retirement eligibility dates will be influenced by, among other things, how the units are operated and maintained over the coming years.

Figure 2.5.19 – Estimated Nuclear Retirement Eligibility by Facility: 2006 – 2025



Source: OPA, with advice IESO and Nuclear Operators

Figure 2.5.20 – Estimated Retirement Eligibility of Ontario's Existing Nuclear Fleet: 2006 – 2025



Source: OPA, with advice IESO and Nuclear Operators

The retirement, refurbishment and potential replacement of Ontario's nuclear facilities will require a substantial degree of coordination. Retirements and refurbishments require sufficient lead-times to permit a predictable, efficient, and cost-effective process. Coordination is further

required to minimize and manage impacts on the reliability of Ontario's integrated power system. For example, too many simultaneous refurbishment outages could lead to resource adequacy challenges for the province, since a single nuclear unit represents a relatively large amount of capacity, and since refurbishment outages can last up to 2 years.

By way of illustration, a single unit at Bruce can supply the average power requirement of the City of Hamilton, while a single unit at Darlington can supply about seven times the average requirement of Thunder Bay, or twice the average requirement of Brampton. Similarly, a single unit at Pickering can supply more than the combined average requirements of Guelph, Kingston, Stratford, Orillia, and Kenora.

Finally, replacement of aging nuclear units with new units would require long lead-times, meeting approval requirements, coordination with respect to transmission integration, and a coordinated approach for securing materials and labour. The development and construction of a new nuclear unit can take up to 12 years.

2.5.5.4 Uncertainty Related to Non-utility Generation Availability

In the late 1980s and early 1990s, Ontario Hydro entered into approximately 90 power purchase agreements with a variety of generators that were not owned by the utility. At present, approximately 23 of these revised contracts remain managed by the Ontario Electricity Finance Corporation. The contracts expire throughout the period to 2048. A number of the revised contracts will expire within the study period (i.e. by 2025), representing well over 1,000 MW. It is uncertain to what extent the contracted resources will remain in service once the contracts expire. The future availability of these resources, therefore, represents an additional uncertainty that must be considered when making planning decisions over the next 20 years.

2.5.5.5 Uncertainty Related to Hydroelectric Capability

In the past, when Ontario had its peak demand during the winter, the peak capacity rating of a hydroelectric station was based on its ability to meet a two-hour uninterrupted period of high demand once a day, for five consecutive days. The peak capacity of a station would be the one that could be attained 98 times out 100, or under what is known as "dependable conditions."

Ontario's electricity demand profile has changed since then. Ontario has gone from a winter peaking system (e.g. due to heating and lighting) to a summer peaking system (e.g. due to air conditioning). Summer peaks can last up to 10 to 12 hours each day.

Summer is, however, the season when natural water inflows (e.g. from rain) are at their lowest and when level fluctuations in lakes, reservoirs, and forebays are most constrained. This means that fuel supply in hydroelectric installations is most limited at the time when it is most needed.

In addition to providing power and energy, hydroelectric resources have always been important sources of peaking and load-following service. It is expected that Ontario will increasingly rely on hydroelectric resources for these services in the future as flexible facilities are removed from service and as resources with limited load following capability (such as wind) are increasingly introduced into Ontario's system.

These factors result in a planning uncertainty related to how much of Ontario's hydroelectric resources can be depended upon during summer peak conditions and for peaking and load following services. Further assessment of these issues is required to gain a greater understanding of the relevant limitations. OPA notes that the IESO has raised the issue in its latest 10-year outlook. For the time being, and until more detailed analysis is available, OPA has derated the installed capacity of Ontario's hydroelectric fleet as a planning assumption to reflect limitations on hydroelectric availability.

2.5.5.6 Uncertainty Related to Incorporation of New Resource Types

Ontario is expected to see an increasing penetration of generation resources over the study period that either exist in relatively small amounts on the current system or are not yet a part of Ontario's supply mix. Such resources include wind generation, inter-provincial purchases, hydrogen fuel cells, biomass, cogeneration, photovoltaics, and gasification. Likewise, Ontario can expect to see a large number of incremental additions of small hydroelectric resources in the future.

The contribution of these resources to Ontario's future supply mix will be shaped by a number of policy, economic, technical, and physical influences. For example, the degree to which wind generation will play a role in Ontario will be influenced, in part, by:

- Policy choices with respect to connection cost allocation for transmission and distribution
- Policy choices related to land use sensitivities and restrictions
- Environmental policies
- Public acceptance
- Improvements in economics, and
- Ability of Ontario's power system to integrate large and increasing quantities of wind generation

Likewise, the extent to which small hydroelectric resources will be exploited will depend on, among other things, factors such as:

- Resource availability
- Transmission and distribution policy
- Land use policy
- Acceptability to Ontarians

Similar factors will influence the inclusion of inter-provincial purchases in Ontario's future supply mix. The adoption of resources such as fuel cells, biomass, cogeneration, photovoltaics and gasification will also be shaped by inter-related policy, economic, and technical factors, including the demonstration of acceptable technical and environmental performance.

All of the above pose uncertainty as to the ultimate contribution of each resource within Ontario's future supply mix, whether it be above or below the planning assumptions developed for supply mix advice (and as outlined in Part 2.8). The planning approach will need to maintain sufficient flexibility to embrace future opportunities as they arise, as well as to adapt whenever they do not materialize as expected.

2.5.6 Environmental Evaluation Methodology

The OPA is faced with the challenge of ensuring Ontario's electricity resource gap is addressed in a way that respects ecological integrity. This challenge is compounded by the fact that the environmental consequences of electricity supply are wide ranging, including acid rain, climate change, smog, exposure to radioactivity and toxic materials, loss of biodiversity, changes to water quality and the production of waste that ultimately must be landfilled.

In addition to being wide ranging, the environmental impacts of electricity generation occur throughout the life-cycle chain. Impacts arising from resource mining through plant decommissioning must be taken into account in order to make meaningful comparisons among electricity options.

Comparing options also requires evaluating impacts that are very different from one another. For example, water use impacts must be evaluated relative to waste impacts or to emissions of air pollutants.[8]

In order to understand potential environmental impacts and how they can be quantified and compared, OPA engaged SENES Consultants Limited to develop an appropriate methodology. The SENES methodology involves a high-level life-cycle assessment of the environmental impacts of each type of generation under consideration. Impacts related to greenhouse gases, contaminant emissions, radioactivity, land, water, waste and resource availability were evaluated.[9]

[8] See Part 2.6 for methodology and Part 4.4 for the SENES report.

[9] The methodology includes a weighting scheme, based on work done by the European Commission, that allows for the comparison of different environmental impacts relative to one another.

2.5.7 Conclusion

In developing supply mix advice to the Minister of Energy, OPA has had to address a number of significant challenges. Ontario stands to lose almost 60% of its generation capacity over the next 20 years, a situation which is unprecedented in the province's history. At the same time, demand continues to grow.

While conservation will play an increasingly important role in curbing demand, the potential magnitude and cost of energy efficiency measures are uncertain. Uncertainty also surrounds future fuel price trends, as well as the ultimate contribution of generation options that are not yet a significant part of Ontario's supply mix.

The OPA must also work towards ensuring that Ontario's resource gap is met in an environmentally responsible manner. The production of electricity can have wide-ranging effects, impacting air, land, and water quality, and can produce substantial amounts of waste.

The unprecedented retirement of resources, considerable uncertainty regarding CDM and other future trends, and environmental impacts are some of the main challenges that will shape the future of Ontario's electricity system. The OPA has taken into account each of these challenges in developing its supply mix recommendations.

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2.6 What Methodology and Assumptions Have OPA Adopted?

In this part, OPA outlines the key methodological approaches and assumptions it has adopted in developing its supply mix advice to the Minister of Energy.

2.6.1 Key Findings

- OPA has adopted the Independent Electricity System Operator's (IESO) most recent 10-Year Outlook, dated July 2005, as its base load forecast and extrapolated it for the supply mix planning period
- IESO's "top-down" forecast was adopted, in part, because the data on end use of electricity necessary to produce a "bottom up" forecast have been unavailable for the past decade in Ontario; like all energy forecasts, the current forecast has an inherent uncertainty
- Peak demand in Ontario is forecast to increase by 1.3% per year, while energy requirements are forecast to increase at 0.9% per year
- Power systems require a balance of resource characteristics to serve different requirements for power, energy, operating reserve, and other services throughout the day and night
- Ontario's load curve has a significant ramp up of 5,000 MW in the morning and a matching ramp down in the evening – generating technologies differ in their ability to change output to follow this ramping
- OPA has adopted a reserve margin of 18% for the longer term
- A level of 65% of total capacity being base load is judged appropriate for Ontario over the next 20 years; peaking/intermediate resources would make up the remainder
- OPA has screened each supply resource option on the basis of its life-cycle environmental impacts
- OPA has analyzed both the "absolute" environmental impacts (such as tonnes of a particular pollutant) and "scored" impacts (that quantify all impacts on the same basis, permitting calculation of the total environmental impact of an option or portfolio)
- Economic assessments were performed both for individual options and for portfolios of options, on a lifetime basis, including allowance for costs beyond 2025
- Risk and uncertainty were key aspects of the economic analysis that included analysis of sensitivity to uncertain parameters and scenario analysis of the robustness of portfolios to different scenarios, for example, higher load growth

2.6.2 Introduction

The key matters related to the methodology and assumptions are:

- Base Load Forecast Methodology
- System Balancing Considerations
- Environmental Impact Methodology
- Economic and Risk Assessment Methodology

2.6.3 Base Load Forecast

The starting point for long-term supply planning is a forecast of demand for electricity in Ontario. A forecast of demand attempts to predict future use of the services that electricity provides. This prediction is rooted in future perspectives on the growth of energy-using stock in the province, as well as the usage characteristics of this stock. Use is the result of many factors, including choice and purchasing decisions, efficiency of available equipment and utilization behaviour.

Models are used to capture the above concepts and produce forecasts of demand. There are several approaches to building these models. Models generally fall into a "top-down" or "bottom-up" approach. In the top-down approach, reliance is put on major trends such as the economy and population driving demand. In the bottom-up approach, demand is built up by specifically considering details regarding the energy-using stock and its usage.

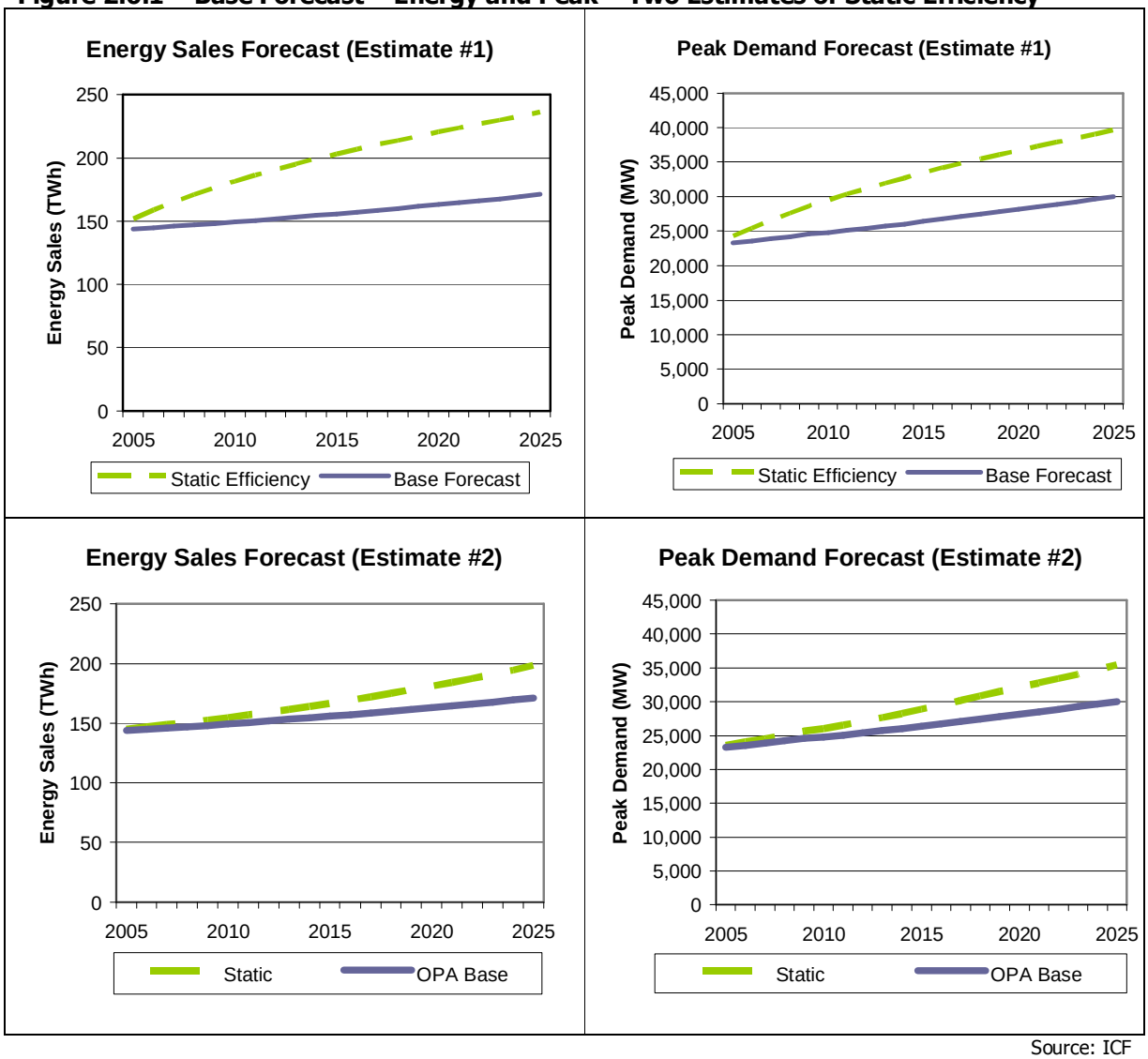
By definition, a model is an imperfect representation of reality. It is impossible to include all the considerations that impact demand. Changes in the health of the economy generally and the behaviour of specific industries will have an effect, as will energy prices, government policy and stochastic processes such as weather. In the end, it must be recognized that energy forecasting is an inexact science with inherent uncertainty. As such, the value of a demand forecast lies in providing a systematic and logical way of thinking about the future rather than as an exact prediction.

The IESO 10-Year Outlook (July 2005) was chosen as the basis for a demand forecast for OPA's future supply analysis. The IESO forecast was produced using a top-down approach. To incorporate the richness of detail required to undertake the CDM potential analysis, a bottom-up approach was used to translate this forecast into stock predictions. It is this forecast that has been labelled OPA's Base Forecast.

The Base Forecast incorporates a level of naturally occurring technological improvement, namely improvements in the efficiency of use that comes about due to normal market forces. Ongoing technical advances improve the quality and energy-using characteristics of equipment. As stock is replaced at end of life, replacement stock can have different energy use

characteristics. Natural improvement may also result due to the ongoing effect of historic programs supported by government agencies. As discussed in Part 4.2, OPA received more than one estimate of the extent of technological improvement incorporated in the Base Forecast. In other words, OPA received more than one estimate of the extent of underlying efficiency already contained in the Base Forecast before the impact of any additional conservation programs or policies is considered.

Figure 2.6.1 – Base Forecast – Energy and Peak – Two Estimates of Static Efficiency[1]



Source: ICF

[1] As noted, the Base Forecast incorporates reductions from technological improvement. Because it is difficult to separate technological improvement and CDM potential, it is useful to be explicit about the level of technological improvement. This is done through "static efficiency" – the Base Forecast plus technological improvement, i.e. the forecast that would have resulted had there been zero technological improvement. In Figure 2.6.1 the differences between the dotted and solid lines are the amount of technological improvement.

For a given static efficiency forecast, if the extent of technological improvement is overestimated, the result would be an underestimation of future consumption. Energy sales are forecast to grow at 0.9% per year, while peak is expected to grow at 1.3% per annum over the planning period. The first estimate for static efficiency yielded values of 2.2% and 2.5% growth per year for energy and peak, respectively. The second estimate for static efficiency yielded 1.6% and 2.0% for energy and peak, respectively.

The conclusions drawn from this exercise to determine the level of technological improvement incorporated in the Base Forecast are:

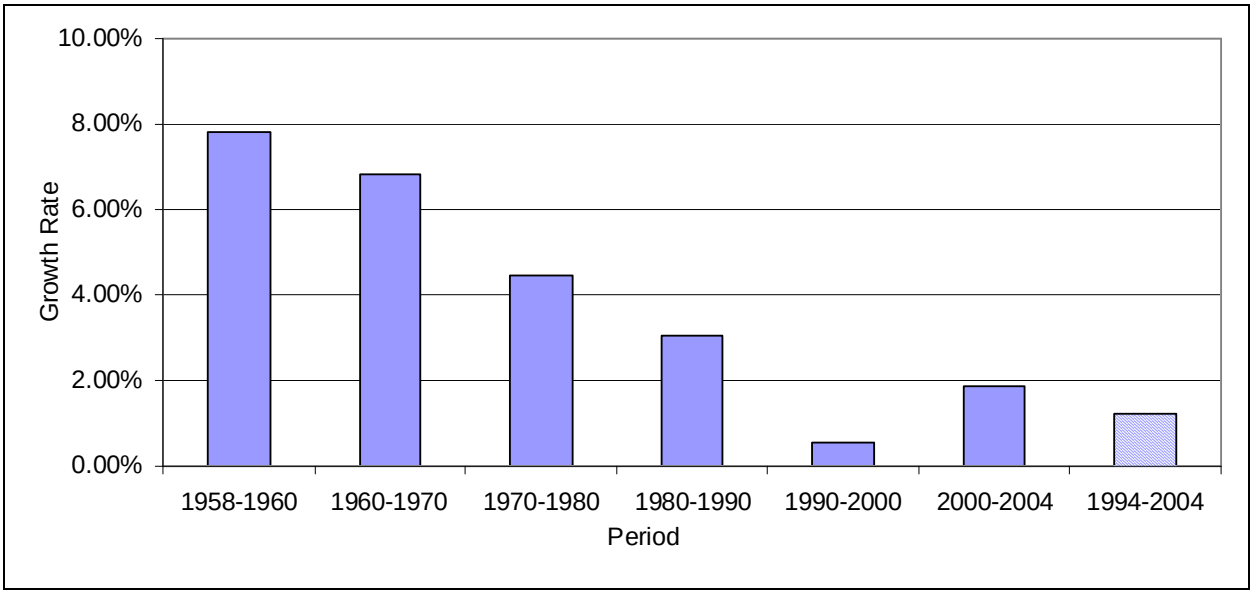
- Estimates of technological improvement levels have substantial uncertainty
- This level of uncertainty, such as the difference between 2.0 and 2.5 annual average growth in underlying demand, corresponds to a significant uncertainty in the amount of new supply resources required by 2025
- There is particular concern that the IESO forecast may incorporate significant overestimates of technological improvement resulting in an OPA Base Forecast that is significantly too low
- This, in turn, suggests the need to allow for consumption levels higher than those in the Base Forecast in developing the supply mix

Figure 2.6.2 puts forecasts of energy in the context of historical growth. There has been a noticeable levelling off of growth since the 1980s. The low growth over the 1990–2000 decade is a reflection of the impact of the 1991-1992 recession. The years post-1993 have seen a revival of growth, although at a much decreased level compared to historical rates.

The Base Forecast's 0.9% annual growth in energy is seen to be slightly lower than the 1.2% level for the past 10 years and substantially lower than the 1.9% experienced in the past 4 years.

More detail regarding the factors associated with historical growth can be found in Part 4.2.

Figure 2.6.2 – Growth Rates for Ontario Electricity Energy Consumption 1958-2004

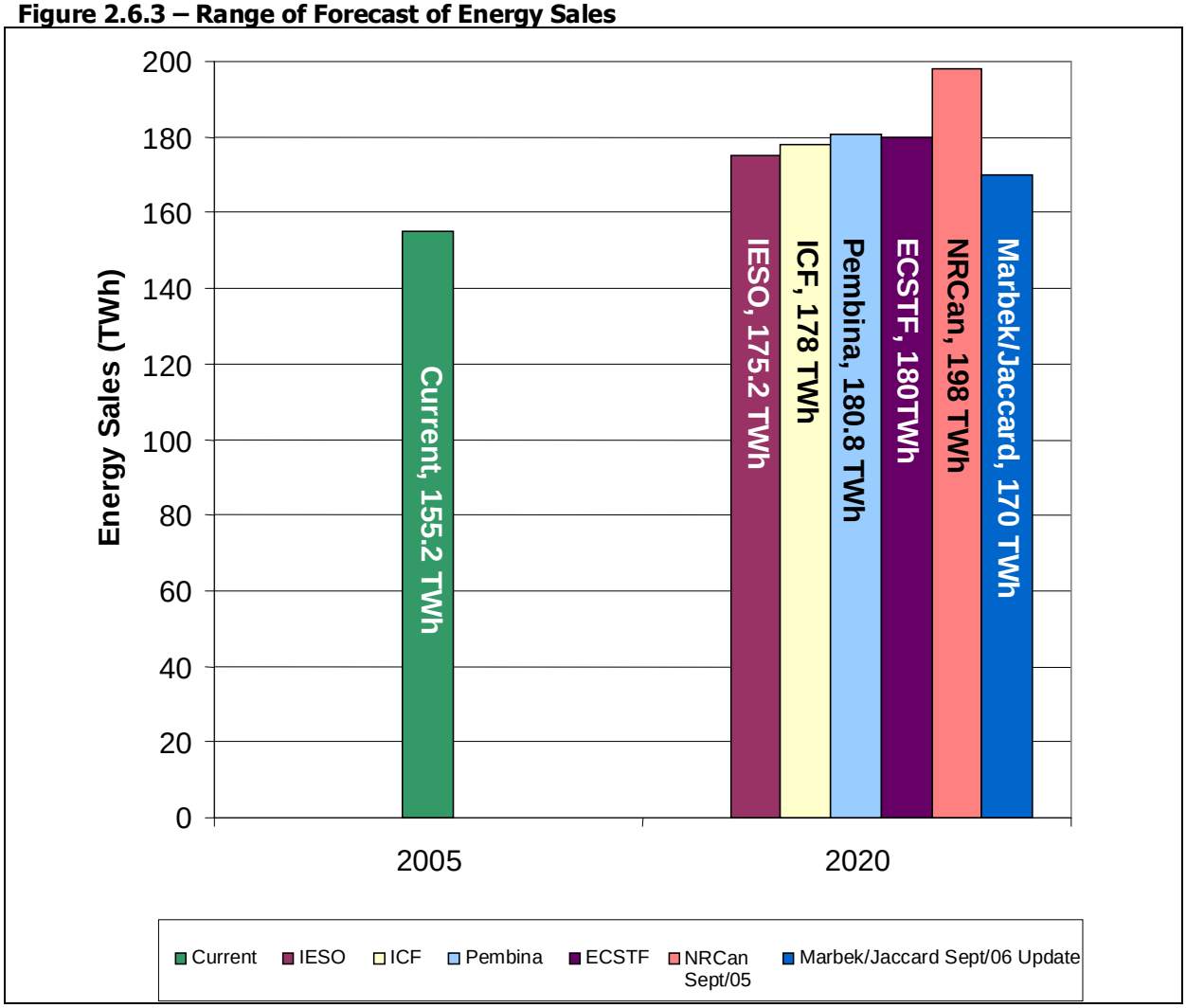


Source: ICF, OPA

Figure 2.6.3 presents a range of forecasts for the year 2020 produced in other studies. The results are relatively close and range from 170 to almost 200 TWh in 2020. Not all studies have used the same starting point or base year in their projections. Although the estimates for 2020 are similar, there are differences in the assumptions regarding the path to getting there.[2]

[2] ICF and ECSTF forecasts are based on the IESO forecast. The Pembina forecast was produced using the M.K. Jaccard & Associates CIMS model, a detailed sectoral and technology specific model; the modellers forecast felt that results were in line with the IESO forecast. The NRCan forecast was produced using the MAPLE-C model, the Canadian version of the National Energy Modeling System (NEMS) supported by the Energy Information Administration (EIA) of the U.S. DOE; MAPLE-C is a detailed simulation model based on economic and engineering relationships. The Marbek/Jaccard forecast was produced recently as part of the Working Group investigating DSM potential in Canada.

Figure 2.6.3 – Range of Forecast of Energy Sales



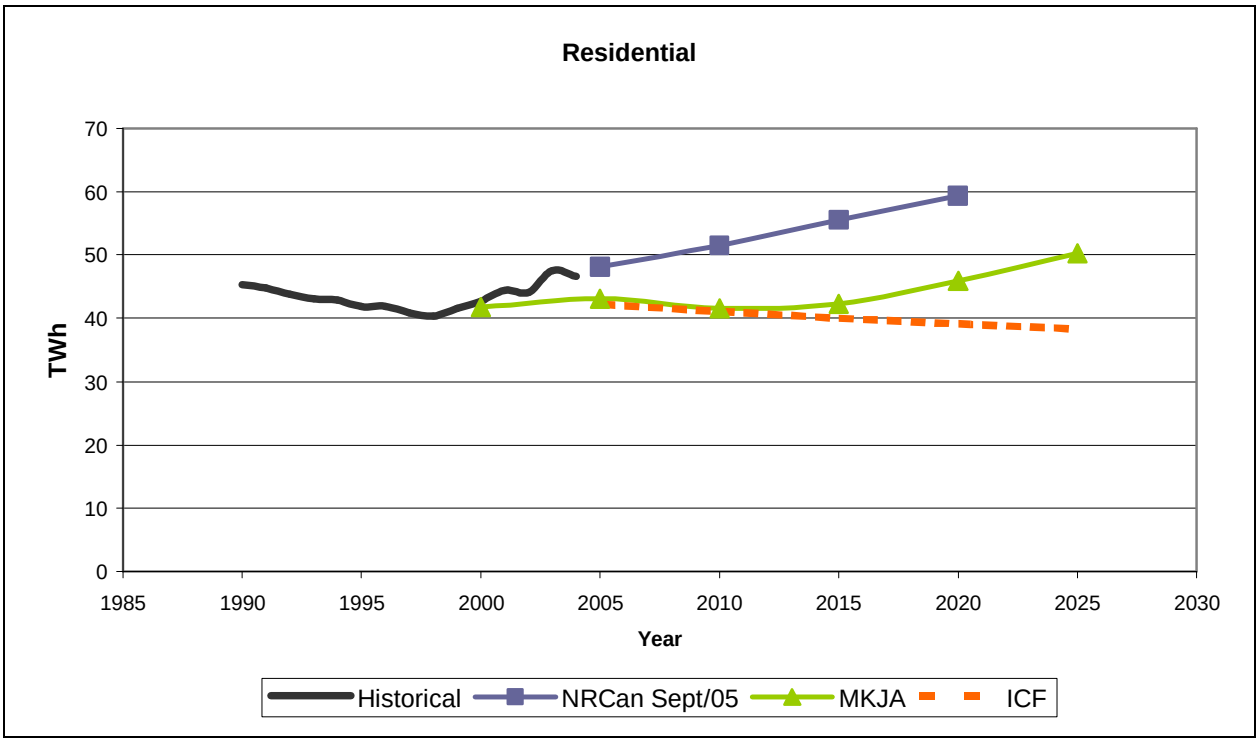
Source: OPA

The extent of similarity among the forecasts is somewhat misleading since both the ICF and the Electricity Conservation and Supply Task Force (ECSTF) forecasts adopted the IESO forecast as their base.To better understand these forecasts, it is instructive to look first at the sectoral results and then at a more macro level.

Figures 2.6.4 and 2.6.5 show the sectoral contributions to the forecasts contained in the ICF, NRCan and recent Marbek/Jaccard studies. Historical trends have been provided to put forecasts of the future in context. Table 2.6.1 compares sectoral growth expectations produced by Ontario Power Generation (OPG), the U.S. Energy Information Agency (EIA), NRCan and ICF. Based on historical trends and comparisons, there are indications that the IESO forecast, i.e. the basis for the ICF lines, and consequently OPA's Base Forecast, may be too low. This conclusion follows in particular from the plots of residential consumption in Figure 2.6.4. It should be recognized that the IESO forecast is a 10-year forecast, not a 20-year forecast as

required for a long-term plan. Although it may be appropriate for the work of the IESO, its appropriateness for the current long-term exercise is less certain.

Figure 2.6.4 – Residential Sales (TWh)



Source: OPA

The Marbek/Jaccard forecast uses 2000 as the base year. This forecast might appropriately be adjusted upward in Figures 2.6.4 and 2.6.5 to bring the 2005 levels in line with the other (more recent) forecasts. This would increase the difference relative to the IESO forecast.

Figure 2.6.5 – Commercial Sales (TWh)

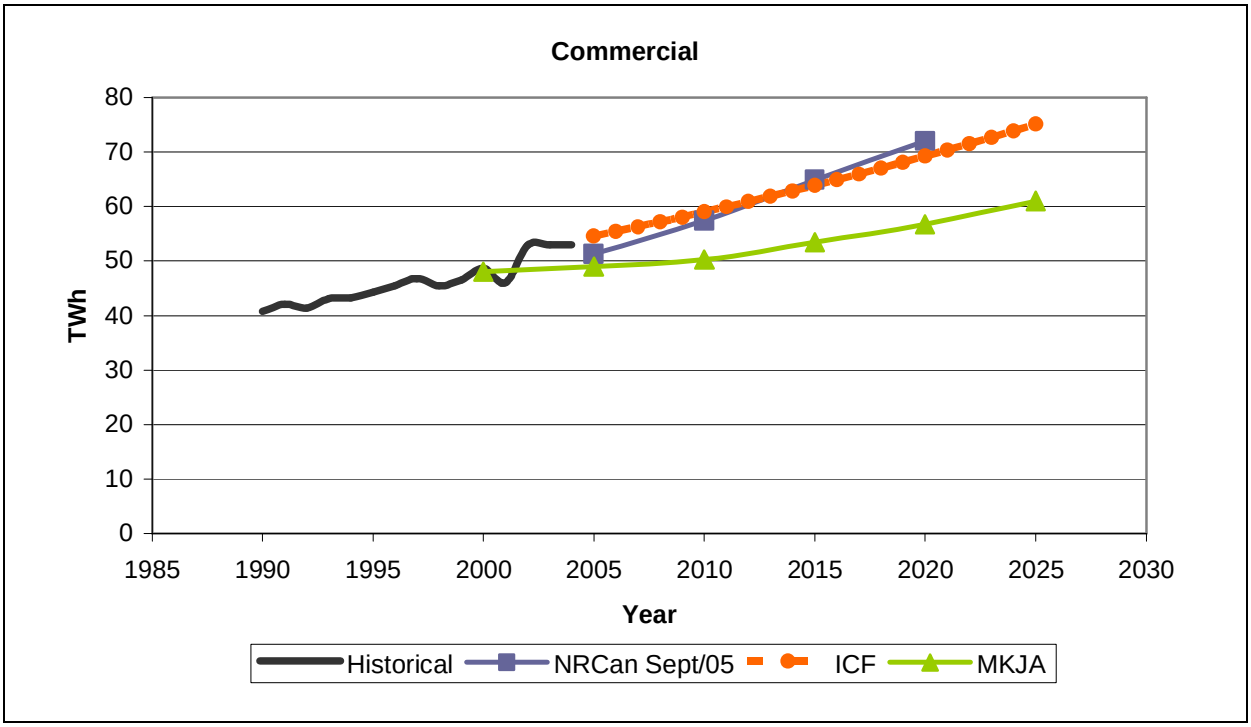
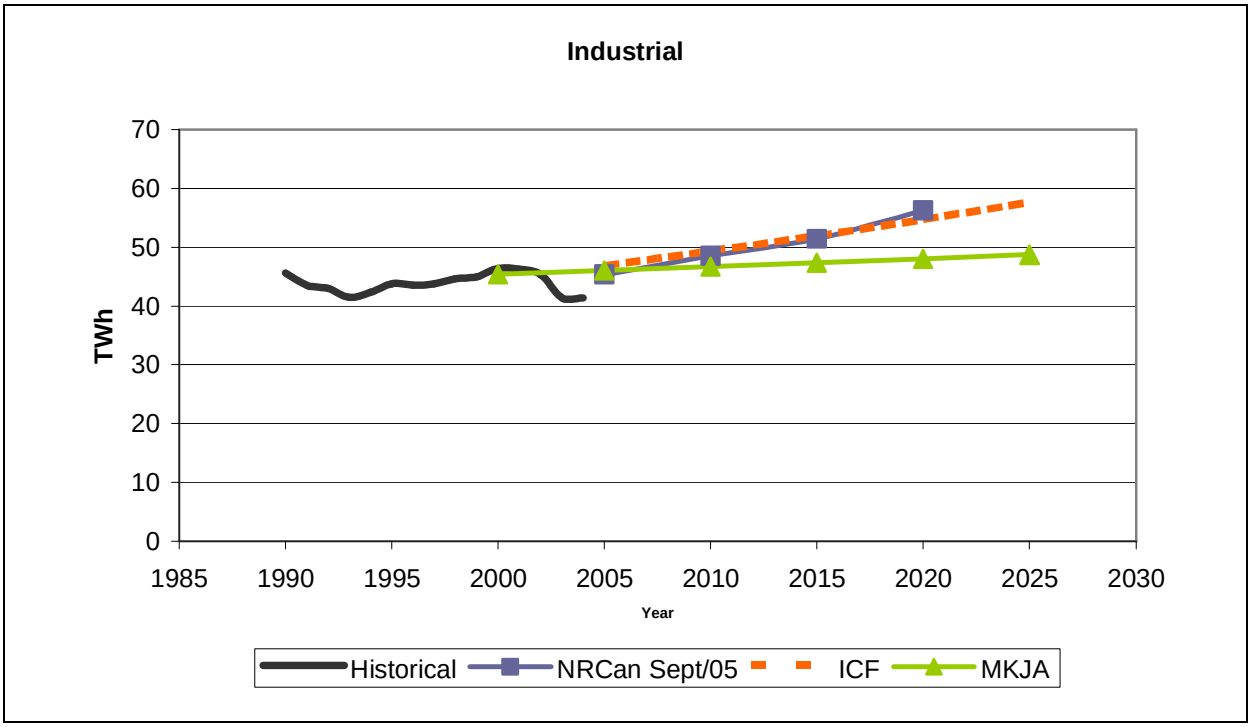


Figure 2.6.6 – Industrial Sales (TWh)



Source: OPA

The IESO forecasts of commercial and industrial sales are seen to be in line with the NRCan forecasts.

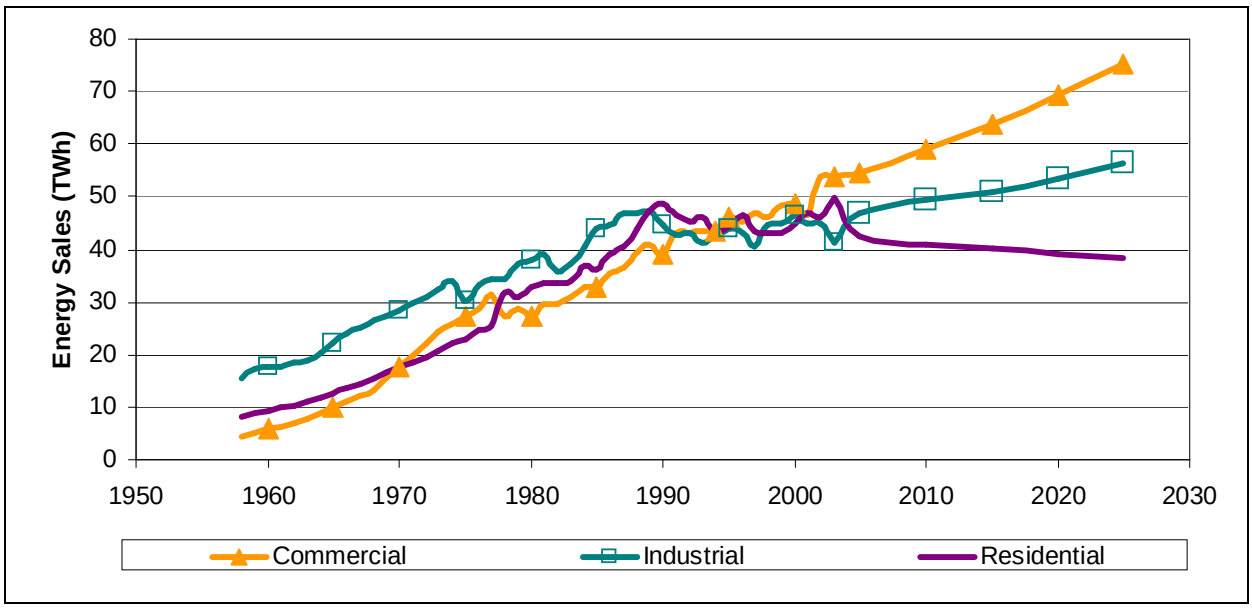
Table 2.6.1 – Load Forecast Comparisons by Sector

	Average Annual Growth (%)			
	OPG 2005-2010	**EIA 2005-2025**	**NRCan 2005-2020**	**ICF/IESO 2005-2025**
Residential	1.1	1.6	1.4	**-0.5**
Commercial	1.5	2.5	2.3	**1.7**
Industrial	1.2	1.3	1.5	**0.9**
Total	1.2	1.9	1.8	**0.9**

Source: OPA

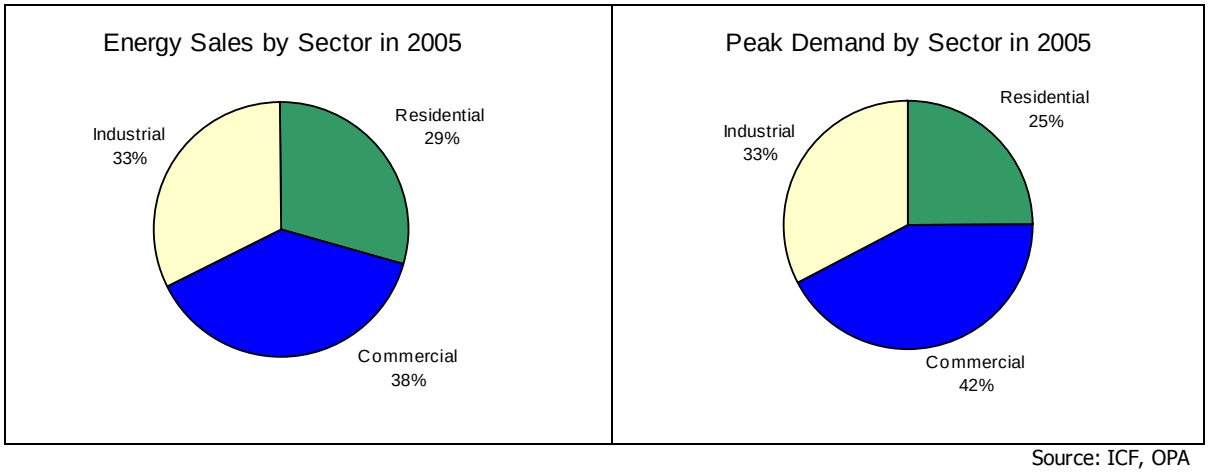
The relative growth between sectors is shown in Figures 2.6.7, 2.6.8 and 2.6.9. OPA's Base Forecast assumes a further increase in the commercial sector's market share of energy and peak demand. The residential sector's decreasing demand into the future will continue to erode its market share. The industrial's share of demand remains relatively unchanged.

Figure 2.6.7 – OPA Base Forecast: Energy Demand Growth by Sector (TWh)



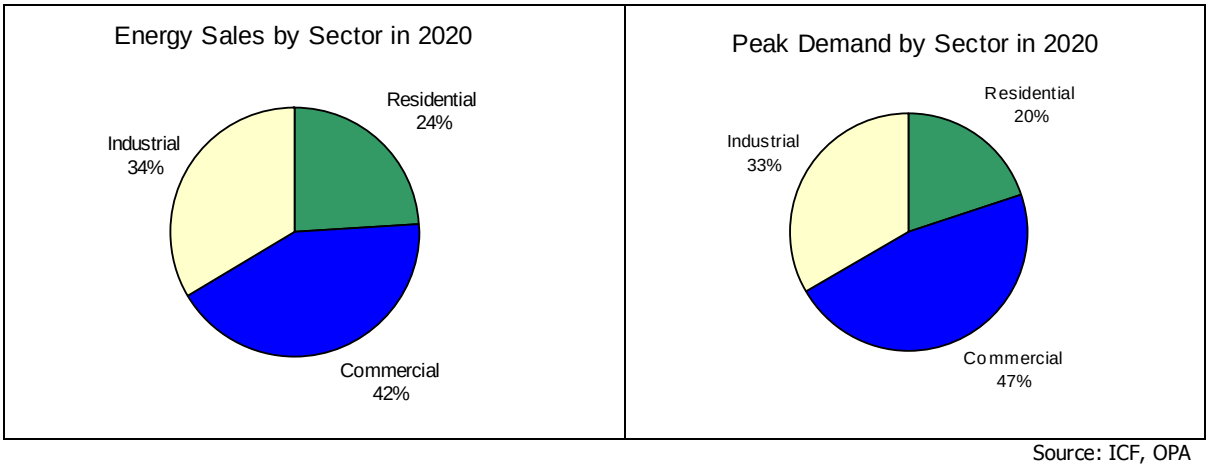
Source: OPA, ICF

Figure 2.6.8 – OPA Base Forecast: Energy and Peak Demand Shares by Sector (2005)



Source: ICF, OPA

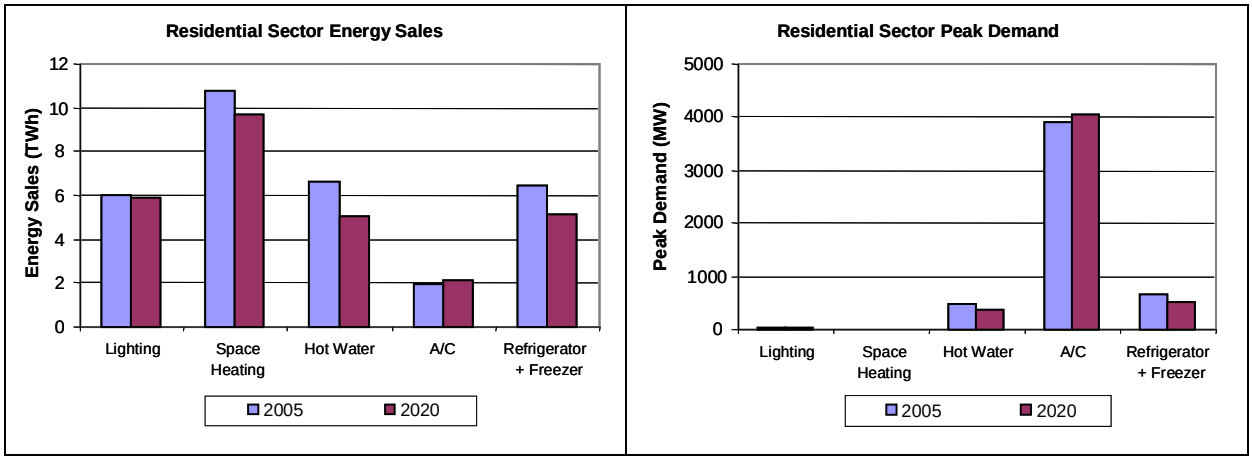
Figure 2.6.9 – OPA Base Forecast : Energy and Peak Demand Shares by Sector (2020)



Source: ICF, OPA

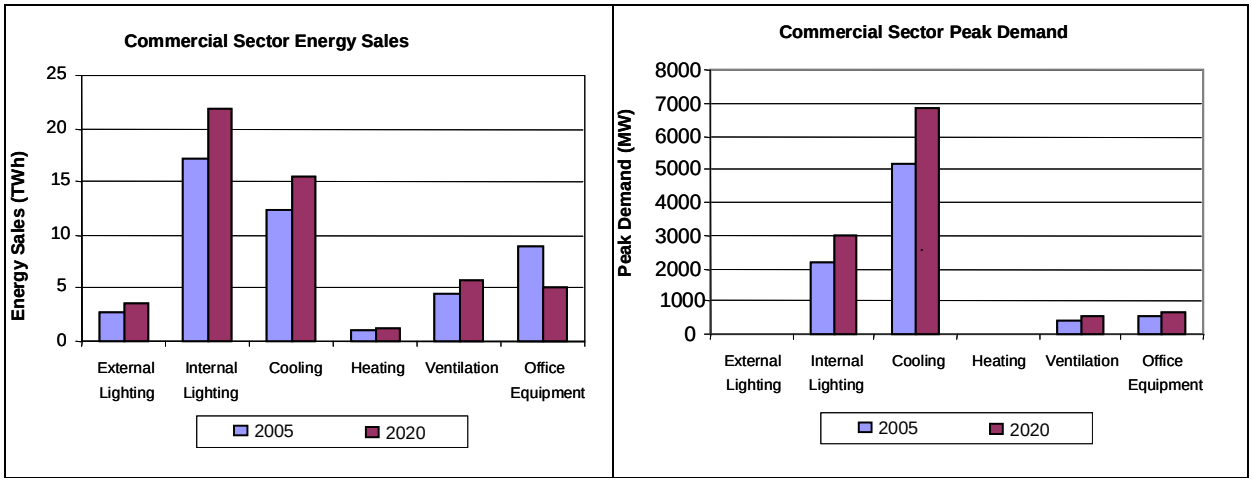
The sectoral end-use breakdowns underlying the OPA Base Forecast are shown in Figures 2.6.10, 2.6.11 and 2.6.12. In terms of energy consumption, residential space and water heating, lighting and refrigerators, commercial lighting and cooling as well as industrial motor drive are the major contributors. In terms of peak demand, residential air conditioning load, as well as commercial lighting and cooling and industrial motor drive, are the dominant contributors.

Figure 2.6.10 – OPA Base Forecast: Residential Energy and Peak Demand by End-use (2005, 2020)



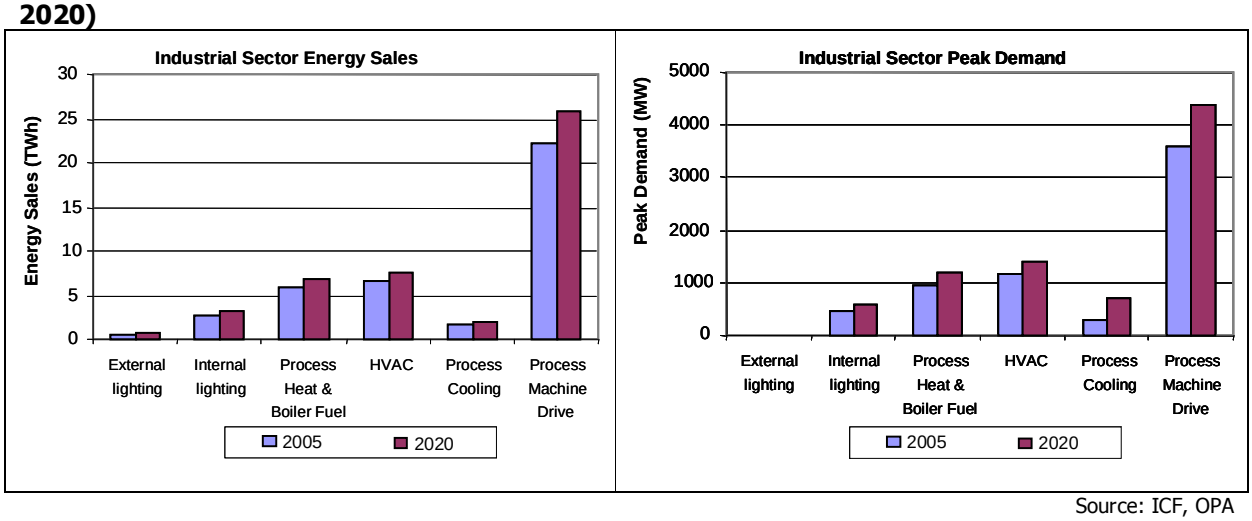
Source: ICF, OPA

Figure 2.6.11 – OPA Base Forecast: Commercial Energy and Peak Demand by End-use (2005, 2020)



Source: ICF, OPA

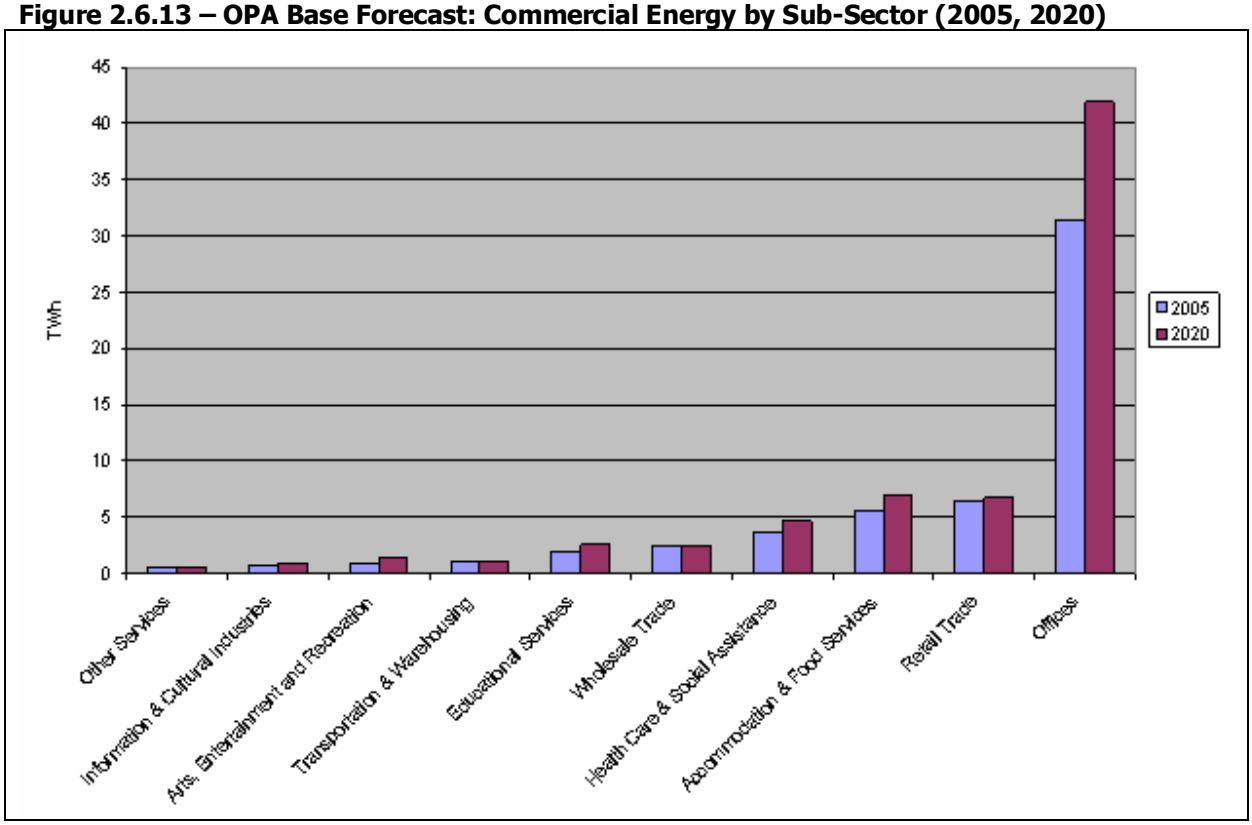
Figure 2.6.12 – OPA Base Forecast: Industrial Energy and Peak Demand by End-use (2005, 2020)



Source: ICF, OPA

Commercial sector consumption can also be viewed sub-sectorally on a business type basis as shown in Figure 2.6.13. The major contribution of offices to demand is evident. The OPA Base forecast assumes electricity consumption by offices to increase annually by 1.9% over the next 20 years, resulting in office share of commercial sector consumption growing from 58 to 61%.

Figure 2.6.13 – OPA Base Forecast: Commercial Energy by Sub-Sector (2005, 2020)



Source: ICF, OPA

A further way of interpreting the forecast is to view it at a macro level with respect to population and Gross Provincial Product (GPP) growth.

One of the major drivers of electricity demand is population. A recent long range assessment of Ontario's fiscal and economic environment was produced by the Ontario Ministry of Finance. It calls for strong population growth of almost 3.3 million people between 1985 and 2005.[3]

Ontario's output (GPP) growth is expected to remain positive with an average annual growth of 2.8%. Growth is expected to slow somewhat compared to historical trends because of slower growth in the labour force. However, because of expected productivity improvements, the amount of output per capita is expected to continue to grow significantly over the planning period.

Figure 2.6.14 – Ontario Population Grows by 3 Million by 2025

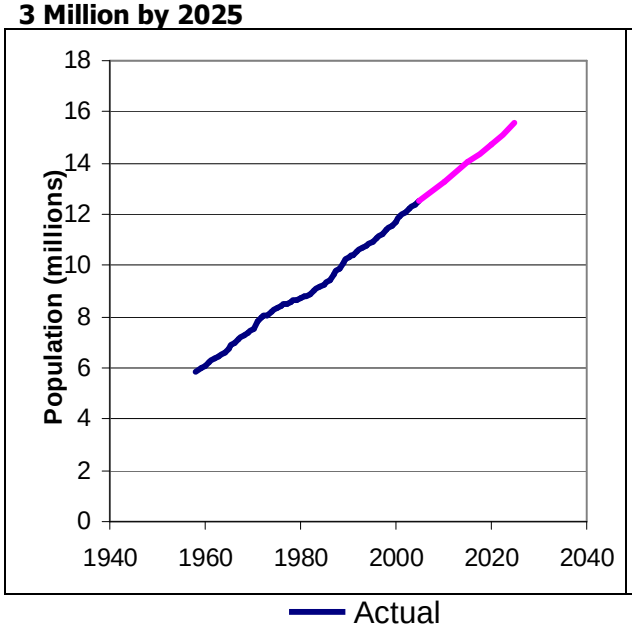
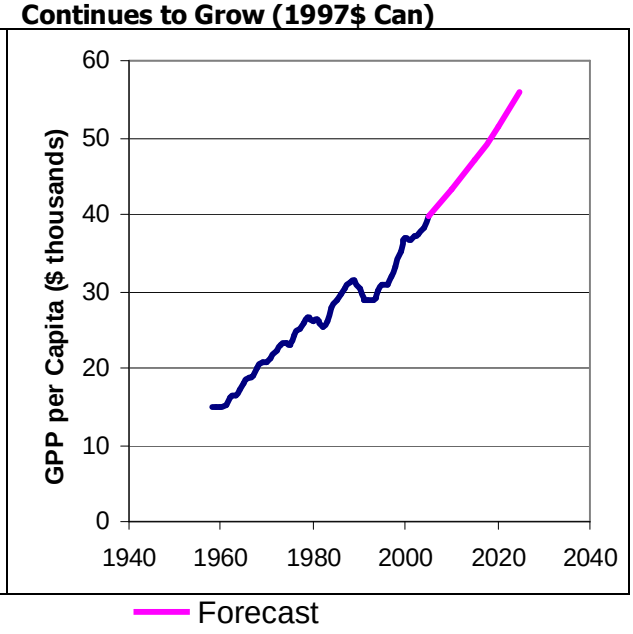


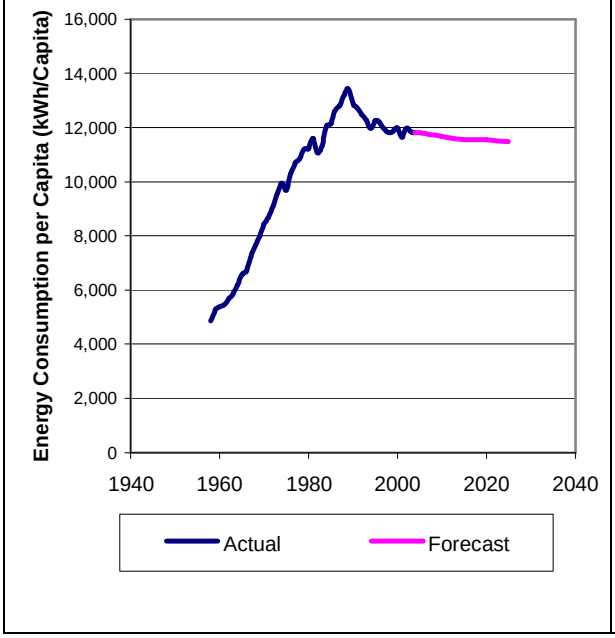
Figure 2.6.15 – Ontario GPP/Capita Continues to Grow (1997$ Can)



Source: Ontario Ministry of Finance

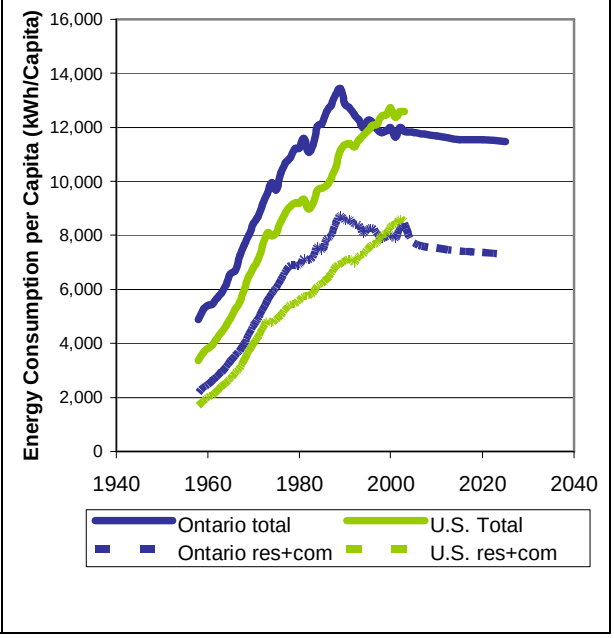
[3] Toward 2020: Assessing Ontario's Long-Term Outlook, Ontario Ministry of Finance, 2005.

Figure 2.6.16 – Electricity Consumption Per Capita



Source: ICF

Figure 2.6.17 – Residential and Commercial Consumption Per Capita



Source: ICF, OPA

Underlying the OPA Base Forecast is the assumption that per capita consumption is not expected to vary significantly from current levels as seen in Figure 2.6.16. Per capita consumption is expected to decrease slightly from its current level of 12,000 kWh, which is at the level of the U.S. average. The per capita consumption is heavily influenced by activity in the industrial sector. Per capita consumption of the residential and commercial sectors provides another picture without the influence of industrial activity (Figure 2.6.17). Although the U.S. per capita consumption trend still appears to be on an upward trend, both on a total basis and without the influence of the industrial sector, Ontario's consumption has levelled off since the 1990s.

Electricity consumed per dollar of economic output is a measure of a jurisdiction's electricity intensity. See Part 3.6 for a discussion of historical trends. Electricity intensity decreases when the growth in electricity use is outpaced by growth in the economy. Again, it is very difficult to compare intensities across jurisdictions because of differences in factors such as climate, industrial mix and age of stock that have major impacts on intensity. A decrease in intensity over time cannot necessarily all be attributed to gains in efficiency, and may be due to structural changes in the economy. Whatever its interpretation, Figure 2.6.18 shows the dramatic decrease in electricity intensity underlying the forecast.

Figure 2.6.18 – Electricity Intensity in Ontario Expected to Decline by a Third

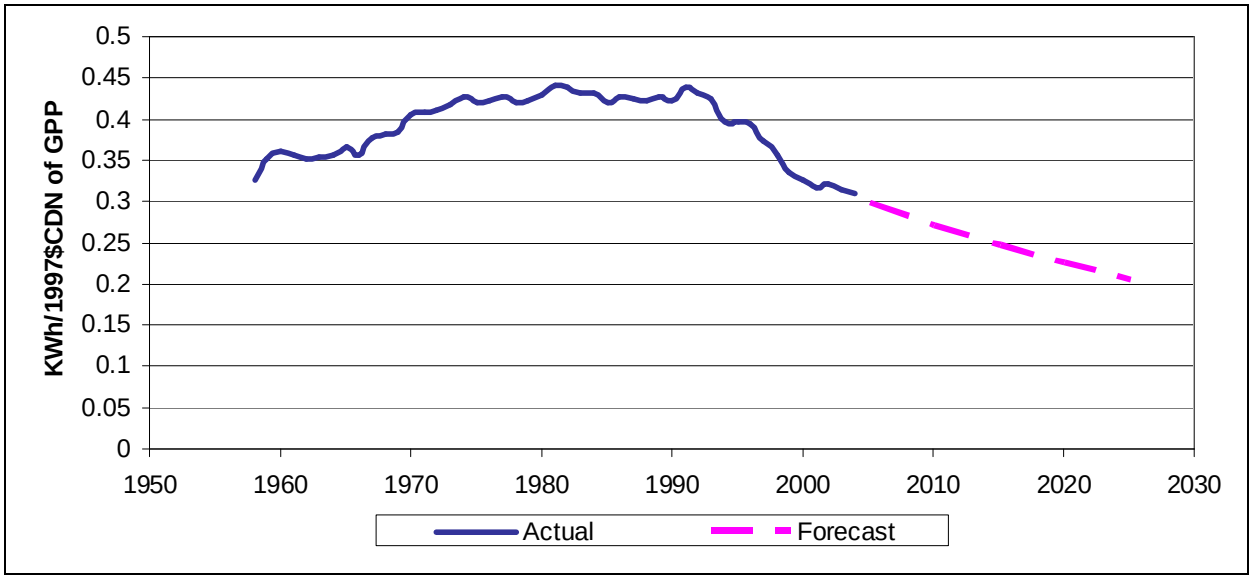
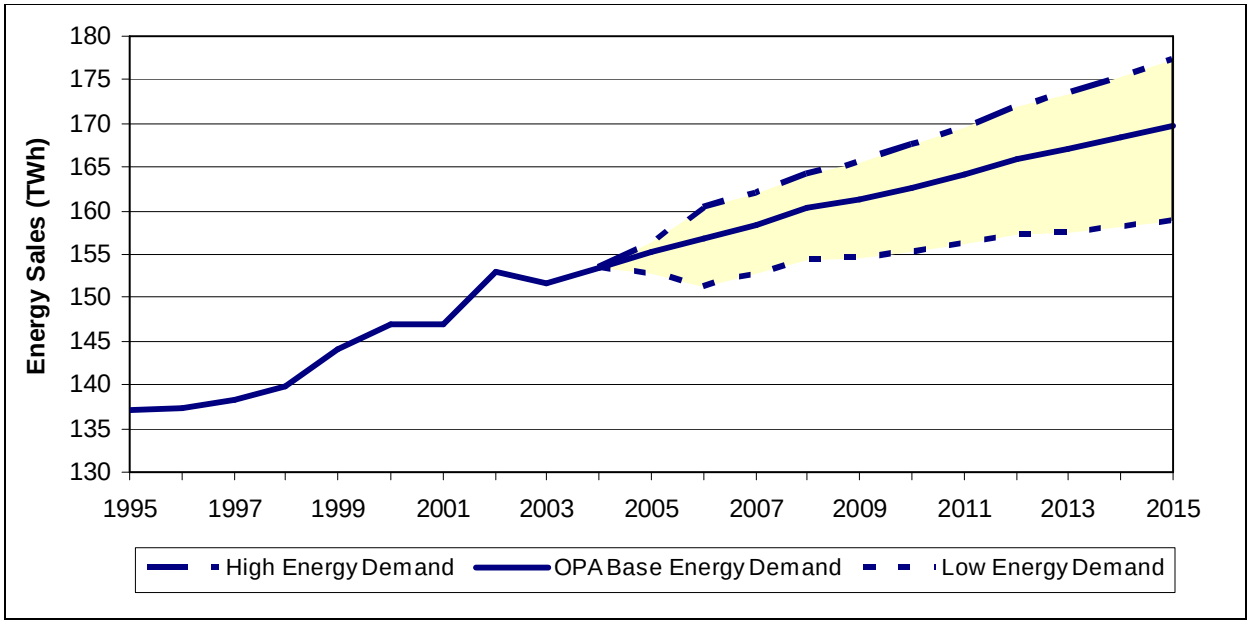


Figure 2.6.19 – Ontario Annual Energy Demand for Different Economic Scenarios



Source: ICF

Scenarios are a valuable tool for investigating the impact on load due to the variation of key parameters. The IESO, in producing its forecast, also produced High Economic Growth (1.3% per annum growth, 177 TWh in 2015) and Low Economic Growth (0.4% per annum, 159 TWh) scenarios (Figure 2.6.19). The Low Economic Growth scenario assumes a recession in 2005-06 followed by a low population growth. The High Economic Growth scenario assumes strong economic growth for 2005-06 followed by high population growth.

It should be noted that this does not represent total uncertainty underlying the load forecast but merely the variation due to changing economic assumptions about the IESO forecast.

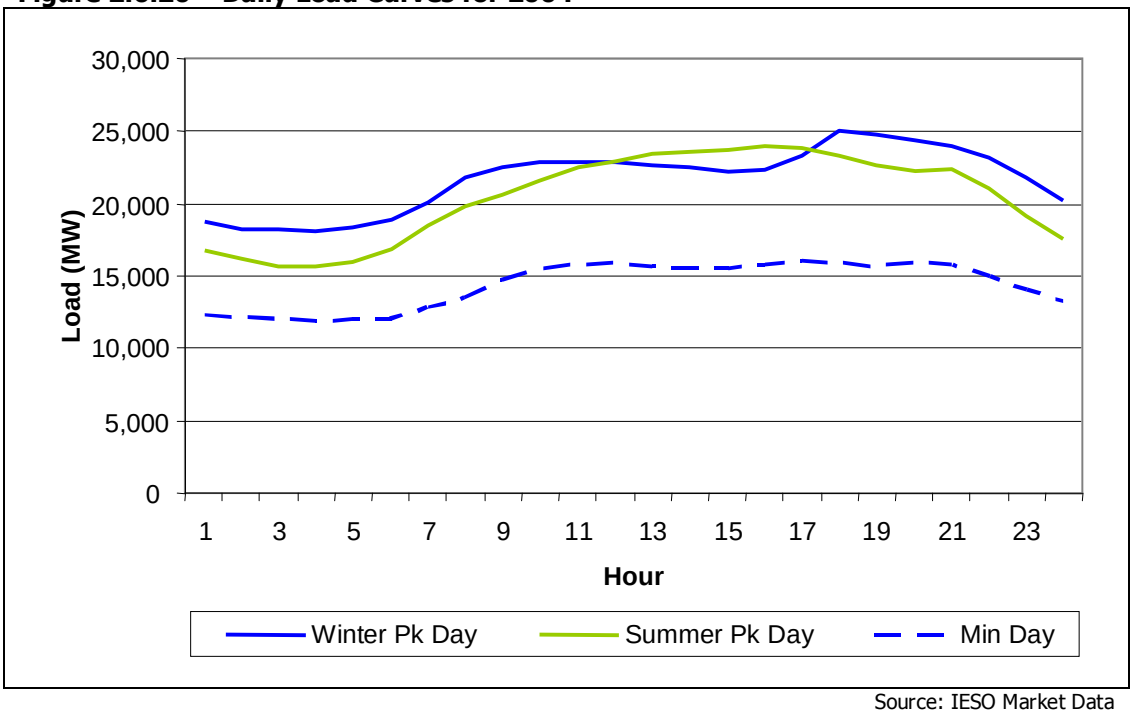
2.6.4 Balancing the System – Base-Load, Intermediate and Peaking Plant

In the request for supply mix advice, the Minister provided specific instruction to OPA on providing recommendations on the proportion of base load, peaking and intermediate resources. This section illustrates the methodology and assumptions involved in such analysis and the approach that was taken.

2.6.4.1 Overview of the Role of Base-Load, Intermediate and Peaking Resources

The demand for electricity varies from moment to moment, but some patterns are clearly apparent. The load tends to be to be low at night and high during the day, but the pattern varies with the season, as shown in Figure 2.6.20.

Figure 2.6.20 – Daily Load Curves for 2004



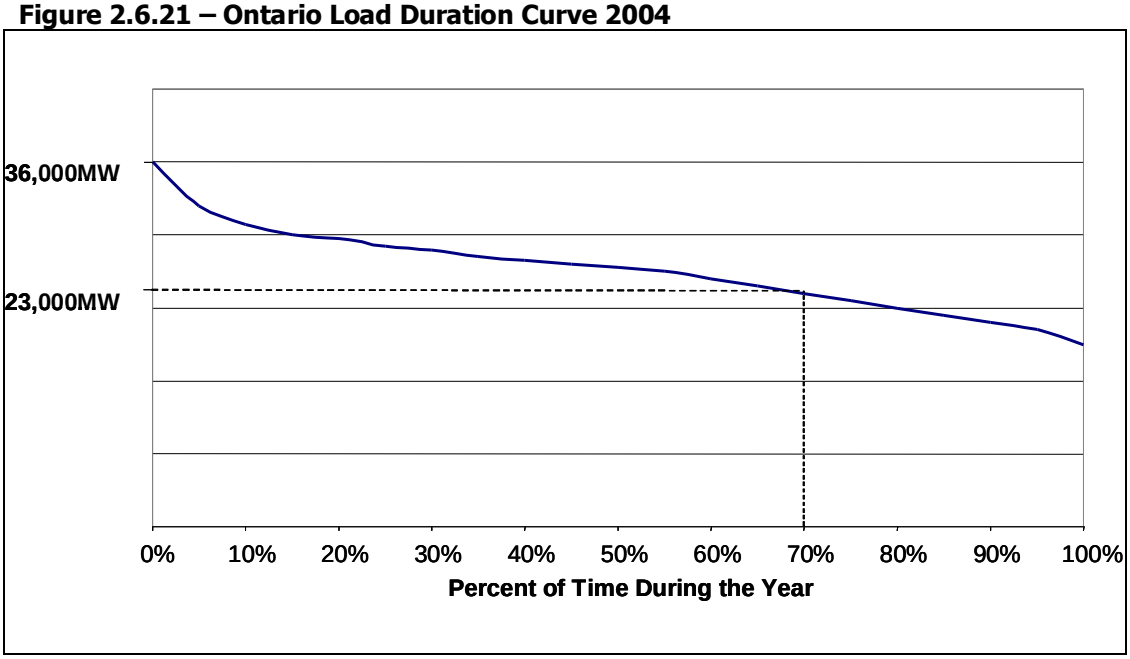
Source: IESO Market Data

Noticeable features of these curves are the rapid rise in the morning and fall in the evening, and the long period of sustained demand during the day. The load displays these general patterns

but occasionally a day will exhibit spikes. A brief spike might occur immediately prior to a popular television program when a large number of sets are turned on.

If the loads over a year are looked at in aggregate ordered highest to lowest, the resultant load duration curve looks as shown in Figure 2.6.21.

Figure 2.6.21 – Ontario Load Duration Curve 2004



Source: OPA

Figure 2.6.21, which is from 2004, can be read as follows:

- Load never fell in Ontario to below 50% of its annual peak value
- Load was within 20% of the peak demand for about 20% of the year
- Load was between 20% and 80% of the annual peak value for about 80% of the time

The conclusions that can be drawn from Ontario's 2004 load duration curve is that base-load generation should be chosen for at least 50% of total capacity, and peaking plant should be chosen for perhaps 20% of total capacity. For the purposes of this analysis, base-load requirements are assumed to meet the load which exists between 70% and 100% of the time. Figure 2.6.21 illustrates that the load which exists 70% of the time (X-axis) corresponds to approximately 63% of total resource requirements at peak (Y-Axis). Assuming the peak resource requirement at 2025 is 36,000 MW, Figure 2.6.21 illustrates that the total base resource requirement at that time should be approximately 23,000 MW (i.e. 63% of 36,000 MW). Peaking resources are assumed to meet load that exists approximately 15% of the time. This corresponds to about 20% on the Y axis, and amounts to a resource requirement of approximately 7,200 MW

at 2025 (i.e. 20% of 36,000 MW). In total, Figure 2.6.21 suggests peaking/intermediate resources requirements to be 13,000 MW at 2025.

A resource with base-load capability is well suited for meeting part of the load that exists much of the time and for continuous operation at constant rates of production. Exceptions to this generalization include wind power, run of the river hydro, and some cogeneration. These resources are used whenever they are available, such as when the wind blows, when the river runs, or when steam is required (in the case of a cogeneration facility).

Base-load resources typically have relatively low marginal costs. Hydroelectric and nuclear are examples. Some base-load resources require relatively long start-up and shut-down times and have limited ability to increase or reduce output in response to short-term variations in demand. Nuclear is an example. Hydroelectric, on the other hand, typically has good manoeuverability. Section 2.6.4.8 considers these factors, which extend the range of base-load resources beyond 50%, and suggests that 63% of total generating capacity should be base-load.

An intermediate resource is capable of increasing its output in response to daily demand swings. The morning and early evening rush hours are examples of such swings, and can account for changes of 5,000 MW or more within several hours. Coal-fired generation and combined-cycle gas turbines are examples of intermediate resources. Intermediate resources will typically have higher marginal costs (fuelling) and greater manoeuverability than base load plants.

A peaking resource is capable of ramping up very quickly to meet brief spikes in demand throughout the day or night. Peaking generation is also capable of providing power and energy on short notice, for example taking up the "slack" resulting from an unexpected loss of another generation resource. Simple-cycle gas turbines and hydro with storage are examples of peaking resources.

In sum, any power system requires a balance of resource capabilities to serve different requirements for power, energy, operating reserve, and other services throughout the day and night, and do so in the most economic manner. Hydroelectric is perhaps the one resource that meets all of these requirements, but unfortunately there is not enough of it to meet all of Ontario's needs. Therefore, a mix of resource types is necessary. Sometimes a brief and rapid response is required, in which case peaking resources are applicable. Sometimes a more gradual response is required, spanning several hours and thousands of megawatts. Intermediate resources serve well in these situations. Likewise, sometimes the requirement is for resources to provide large amounts of output for lengthy periods of time and at low marginal cost. Base-load resources are best in these instances.

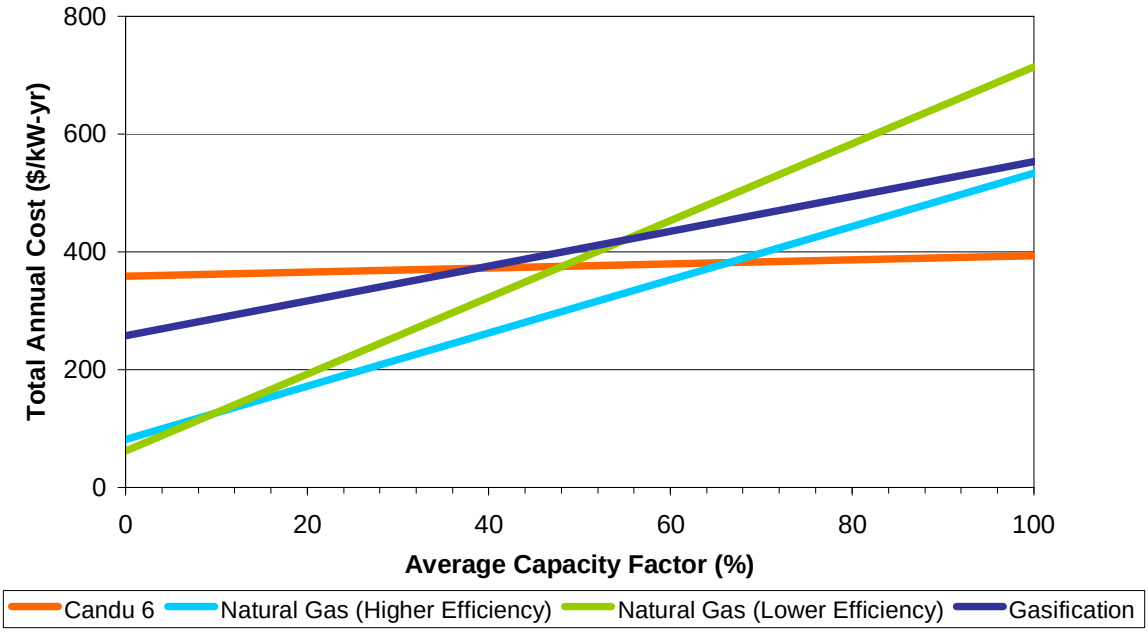
2.6.4.2 Choices of Types of Generation: the Economic Considerations

We have seen that there are three types of generation plant – base, peaking and intermediate. The essential economic differences between them concern the relative magnitude of their fixed to variable costs. The basic definitions are as follows for these characteristics:

- **Fixed Costs**: The costs related to the cost of constructing the plant, making capital improvements to plant over its useful life, and plant decommissioning. In an accounting sense, these costs become expenses in the form of interest charges on borrowed funds and depreciation charges. Some operating costs will also be fixed – ongoing activities that must be undertaken. Essentially, these charges are fixed in the sense that they are incurred whether or not the plant is operating.
- **Variable Costs**: The costs of operating the plant, the ones that vary directly with the amount that the plant is run. These costs will include fuelling costs and maintenance related to usage and wear.
- **Base Load Plant**: Plant that has a relatively low portion of its total costs as variable costs. Its overall economics improve the more it is used – its unit cost is lowered as a result of its fixed costs being spread over a higher level of output.
- **Peaking Plant**: Plant that has the opposite characteristics of base-load plant. Its fixed costs are relatively low, and its variable costs are high. It is therefore attractive for generation that will be required a relatively small portion of the time – it is inexpensive to build, and while its operating costs may be high when it runs, these high costs are incurred for only a small portion of the time.
- **Intermediate Plant**: As its name suggests, an intermediate plant's cost characteristics lie between these two extremes.

The relationship between fixed versus variable cost and time is illustrated in Figure 2.6.22. This is a simplified picture that assumes there are four candidates for a new plant, covering each type of cost structure. The total annual costs are shown as a function of the proportion of time the plant would operate.

Figure 2.6.22 – Breakeven Analysis Based on Capacity Factor*



*Gasification includes sequestration. Source: OPA

Figure 2.6.22 is intended to illustrate the choice for a new plant from among the three basic plant types of base, intermediate and peaking.

As noted, different generation types will have different proportions of fixed to variable costs. Therefore, at low usage (average capacity factor, or ACF) the resource having the lower fixed cost will tend to have the lower total cost. Conversely, at high usage, the resource with the lower variable cost will tend to have the lower total cost.

It will be seen that:

- New gas turbine peaking plant (GT) and mid-merit (intermediate) plants have a break even capacity factor of around 10-15%
- New base-load resources, such as nuclear, typically will be most economic when the plant is used 50% or more of the time
- New intermediate resources, such as combined cycle plant, will be most economic when the plant is used between 25% and 50% of the time

As previously noted, however, the distinction between peaking and intermediate resources in terms of the operational flexibility requirement, is moot. Also, the flat nature of the load duration curve means that targeting specific amounts of intermediate plant is not a useful exercise. Accordingly, the peaking and intermediate categories have been combined.

2.6.4.3 Choice of Types of Generation: Operational Considerations

There are some additional factors that need to be considered in deciding the amounts of base and peaking/intermediate resources:

- Base-load generation usually has some flexibility to "load follow". Load following is the action of varying output up and down in real time or to shut down output for an extended period. Alternatively, surplus energy can be sold on the interconnected market. This flexibility will tend to increase the portion of base load that is economic.
- Additional resources must be allowed for in order to provide the required planning reserve margin. This is particularly important in determining peaking requirements.
- The contribution of "must-run" stations on base-load requirements must be considered.
- The load duration curve does not capture the need for resources to provide operational flexibility to meet changes in output of intermittent resources on a minute-to-minute and hour-to-hour basis, as would be required for significant amounts of wind generation.

Each of these considerations is discussed in turn below.

2.6.4.4 Operational Flexibility Considerations

Figure 2.6.20 indicates that Ontario's load curve has a significant ramp up in the morning and a matching ramp down in the evening. This ramping is in the order of 5,000 MW for each cycle. In this circumstance, generating plant has to be able to change its output fast enough to respond to this change.

Response capability is not only needed for this purpose. The generating system, as a condition of meeting reliability standards, has to be able to respond to system contingencies.[4] In particular, generation must be sufficiently responsive to be able to maintain specified frequency and voltage levels upon the unexpected forced outage of the largest generation unit on the system or the heaviest loaded transmission line or right-of-way.

Different generating technologies have different capabilities to respond to requests for changes in output. Hydroelectric plant has load-following-response capability that is almost instantaneous. Simple cycle natural gas-fuelled combustion turbines also have rapid response times. Existing conventional coal-fired plant and gas-fired combined-cycle plant can respond less quickly, but they can respond. Nuclear plants have generally very little capability.

Additional flexibility considerations are also incorporated in chronological models with maintenance outage scheduling algorithms and with modelling the export/import requirements of the neighbouring jurisdictions.

[4] A system contingency is an unexpected event having potential to impact negatively the reliability of the system, such as, for example, a generator or transmission circuit that goes out of operation.

2.6.4.5 Reserve Margin Considerations

The planning reserve is the excess of generation over the peak system demand in any year. It is usually expressed as a percentage of peak demand. The planning reserve is put in place to allow for the fact that demand is sometimes higher than expected, and that the planned generation resources are not always available to generate when required.

The planning reserve is calculated using estimates of the peak load and allowing for firm purchases, if any. The calculation also allows for the variability of the loads due to weather, economy and other random factors. The variability of the availability of the generating plant, due to such factors as breakdowns, maintenance requirements, etc., is also modeled. A reliability target, expressed in terms of the probability of loss of load, of 0.1/year, is used to determine the required reserve.

While the uncertainty in the loads to be met increases with time, the reserve margin does not increase indefinitely. It is recognized that, with sufficient lead-time, new resources can be brought on stream, so the reserve margin is capped at a long-term value.

For the first ten years of the study, OPA has used the reserve margins used by the IESO in its latest 10-year outlook for the years 2006-2015. The levels for 2016 and 2017 were chosen to provide a smooth transition to the value of 18% for the remaining years of the planning period.

The use of an 18% reserve margin is based on the assumption that long-term reserve requirements should be generally higher than short-term values to reflect greater uncertainty associated with the demand forecast, as well as the performance of new generating units, which may be, in some cases, based on new technology. Time did not permit a rigorous derivation of required reserve margins, so a simplified approach was used, namely to choose a value, 18%, on the basis of consistency with other jurisdictions such as the New York Independent System Operator (NYISO), which also uses 18%. The values used are tabulated below.

Table 2.6.2 – Planning Reserve Margins

Year	Required Reserve (%)
2006	16.4
2007	14.6
2008	15.1
2009	14.5
2010	13.8
2011	13.7
2012	13.8
2013	14.2
2014	14.8
2015	15.1
2016	16.0
2017	17.0
2018	18.0
2019	18.0
2020 - 2025	18.0

Source: OPA

In developing the portfolios, this reserve margin was applied to the load forecast after the effects of CDM and other customer side of meter programs were subtracted. This, in effect, assumes that the CDM resource has no associated reserve requirement. Moreover, the effect of CDM is to reduce the overall reserve requirement (because the 18% is applied to a smaller base).

A second simplification concerns plant mix. The effect of changes in the generation plant mix on the reserve margin has been ignored. A more rigorous approach would associate larger reserve margins with larger plant size.

2.6.4.6 Energy Limited Plant Considerations

The energy-limited plants, such as hydroelectric plants with reservoirs that can be dispatched, are scheduled to use their energy as much as possible in the high demand (and high economic value) periods. The impact of such hydroelectric resources can therefore be considered as a type of peaking resource. The portion of total installed capacity that can be considered peaking, i.e. available to meet peak demands, will depend on factors such as their energy storage capacity. Energy-limited plant is addressed at greater length in Part 3.6.

2.6.4.7 New Intermittent Resources

While some hydroelectric resources are energy limited, they are amenable to a degree of management, and they can be dispatched as needed by a system operator. This is not true for wind and photovoltaic resources, termed intermittent, where output is beyond human control

due to dependence on availability of wind and sun. As a result, the installed capacity of such resources must be derated to arrive at their ability to contribute to meeting the annual system peak demand. In this exercise OPA has taken 10% of installed wind capacity as being assumed available to meet system peak demands.

2.6.4.8 Future Resource Type Requirements

From the above analysis of balancing the system, there is no single definitive and calculable answer for the amount of base and peaking/intermediate required. Judgment will inevitably be necessary.

As described in Section 2.6.4.1, load in Ontario does not fall below 50% of its annual peak value. This implies that base load generation should be chosen for at least 50% of new capacity requirements.

The level of base load can be greater than 50% to allow for:

- Planned outages of base load limits – i.e. units that will be unavailable
- Manoeuvrability of output, i.e. the ability to decrease output
- The ability to export power in excess of Ontario requirements

Analysis, based on nuclear characteristics, suggests that 63% of total required capacity should be from base-load plant. From the Ontario load duration curve it is seen that 65% of capacity corresponds to defining base load as capacity that operates 70% of the time.

For peaking/intermediate plant, the amount of new generation was determined to correspond to meeting requirements at least 20% of the time, or equivalently that at least 20% of the total requirement be peaking/intermediate plant. This amount is significantly higher than that suggested by the LUEC break-even analysis shown above, reflecting the need for a significant amount of plant with substantial operational flexibility. Given that the 63% for base load can be regarded as an upper limit, the amount of peaking/intermediate capacity will, by definition, have to be in the order of 35%.

Ontario's primary challenge for the period to 2025 is one of obtaining sufficient base-load capacity, i.e. to reach the 65% level.

The recommended contribution of the three generation types is shown below.

Table 2.6.3 – Base-Load and Peaking/Intermediate Supply Resource Requirements

Requirement At 2025			
Supply Type			**MW**
Peak & Intermediate (37%)			**13,000**
Base Load (63%)			**23,000**
Service Type	**Requirement At 2025 (MW)**	**Current Fleet Remaining at 2025 (MW)**	**Gap at 2025 assuming only Current Fleet Remaining (MW)**
Peak & Intermediate	13,000	7,000	**- 6,000**
Base Load	23,000	5,000	**- 18,000**
Service Type	**Requirement At 2025 (MW)**	**Current Fleet Remaining + Procurements (MW)**	**Gap at 2025 assuming Current Fleet Remaining + Procurements (MW)**
Peak & Intermediate	13,000	12,000	**- 1,000**
Base Load	23,000	9,000	**- 14,000**

Source: OPA

2.6.4.9 Portfolio Analysis, Base-Load and Peak/Intermediate Considerations

The base-load and peaking/intermediate considerations discussed in the previous section were applied as guidelines in the subsequent stages of the analysis dealing with portfolios of options. Portfolios were initially assembled with roughly 65% base-load capacity and the resulting dispatch of the system was examined to ensure that parameters were in reasonable ranges with respect to economics and system operability. These parameters included the capacity factors (degree of usage) of the gas turbines (peaking plant) and nuclear (if any). The amounts of plant were also perturbed to see if lower cost solutions were available. When nuclear was found not to be operating as base load, it was assumed that a proportion of the unused nuclear capability would be exported.

The LUECs were used to screen the various options, prior to the development of portfolios and scenarios. Extensive simulations were then run based on these portfolios and scenarios, on which the main analytical results are based (these results are reported in Part 2.9). Details regarding the simulation model and methodology can be found in section 2.6.6 of this part.

2.6.5 Environmental Methodology

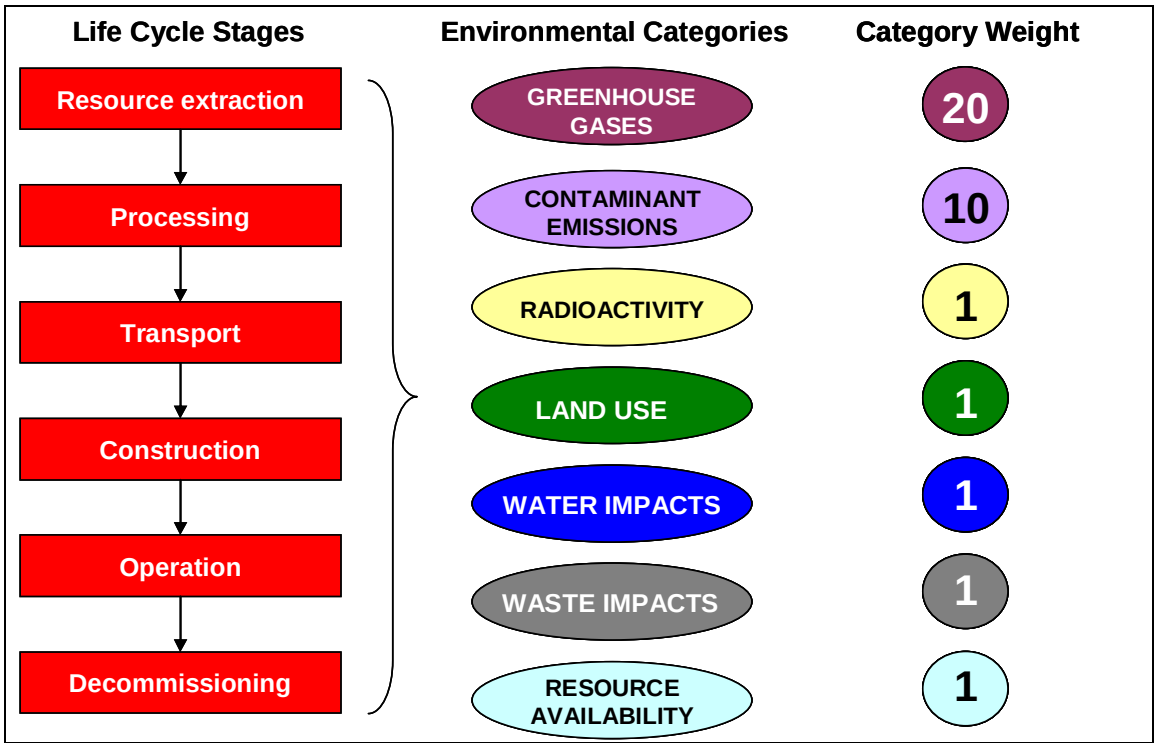
In recent decades, awareness of the environmental consequences of human activity has been increasing steadily. Since electricity production is an activity that can have significant impacts

on ecological integrity, addressing these effects in a comprehensive and responsible way is an important and significant challenge.

2.6.5.1 Methodology

In order to assess potential environmental consequences of generation options for the supply mix advice, OPA retained SENES Consultants Limited to develop an appropriate methodology. The chosen methodology involves a high-level life cycle assessment of the environmental impacts of each type of generation under consideration. Impacts related to greenhouse gases (GHGs), contaminant emissions, radioactivity, land, water, waste and resource availability were evaluated. A general schematic of the methodology is presented in Figure 2.6.23.

Figure 2.6.23 – Life Cycle Methodology



Source: OPA

Since OPA is considering the broad "supply mix" for the province, rather than specific projects, the environmental impacts analyzed are necessarily not site specific. The analysis is intended to provide an assessment of the relative environmental consequences of different resources and portfolios of resources.

2.6.5.2 Life-Cycle Assessment

The environmental impact of generating electricity extends well beyond the impacts of generation operation alone. Not only does the electricity have to be generated, but the resources to build and fuel the plant must also be extracted, processed and transported, and the plant itself must be constructed and ultimately decommissioned. Each of these stages can have significant environmental impacts and should, therefore, be considered. This is the goal of life cycle assessment – to capture the environmental effects at each stage of the life-cycle chain.

SENES has reported on each of the life-cycle impacts for each generation option in terms of impact per unit of energy produced or per unit of plant capacity. For example, in terms of energy, the number of kilograms of pollutant or litres of water that are associated with a megawatt-hour of a particular generation option have been reported. In terms of capacity, the square kilometres of land associated with a megawatt have been reported.

2.6.5.3 Environmental Impacts Considered

The environmental impacts that OPA has considered, and the reason for their inclusion, are presented below.

Contaminant Air Emissions: Contaminant air emissions refer to non-radioactive and non-greenhouse gas airborne pollutants. These emissions can be created at several stages in the life cycle process. For instance, they can be created when fossil fuels are burned to create electricity, during extraction activities such as mining, or from the exhaust of vehicles used to transport materials. Contaminant emissions include nitrogen oxides, sulphur dioxide, particulate matter, and hazardous air pollutants.

When released into the atmosphere, nitrogen oxides and sulphur dioxide transform into sulphuric and nitric acid, which are the source of acid rain. Acid rain can cause devastating effects to water and soil systems, damaging flora, fauna and non-living infrastructure. Nitrogen oxides also contribute to smog. Particulate matter consists of airborne particles that are small enough to remain suspended in air, and contribute to smog and lung disease.

Hazardous air pollutants that are analyzed in this report include mercury, benzene, and formaldehyde. Mercury is a toxic metal that can cause neurological, psychological and pulmonary disease and has been associated with birth defects. Benzene and formaldehyde are volatile organic compounds that, among other things, contribute to smog.

Each of these contaminant emissions has been normalized on the basis of its human health impacts. This way the impact of the different emissions are put on a comparable basis and can be represented by a single number.

Greenhouse Gases: Greenhouse gases (GHGs) trap the heat of the sun in the atmosphere and contribute to climate change. Like contaminant emissions, these gases can be produced at several life cycle stages. The GHGs assessed in this analysis include carbon dioxide, methane, and nitrous oxide. As GHGs, methane and nitrous oxide are 21 and 270 times more destructive than carbon dioxide, respectively. Again, by measuring each GHG in terms of its environmental impact, all GHG emissions are put on a comparable basis and may be added together and expressed as a single number.

Radioactivity: Radioactivity consists of high-energy atomic or subatomic particles or electromagnetic radiation. When these particles and radiation penetrate the human body, they cause biological damage that can initiate cancers and cause genetic disease in children. Radioactivity is absorbed by body tissue and is often reported in terms of collective dose – the dose received by the population as a whole, termed collective dose, is measured in Sieverts.

Exposure to radioactivity occurs not only during the nuclear life cycle, but also over the life cycle of coal, gas, and oil-fired generation. In fact, studies indicate that the collective exposure to radioactivity is far greater for coal than for the nuclear life cycle.

The data used in this analysis are based on normal operation and do not include exposure arising from extraordinary accidents or malfunctions. However, SENES did review the Environmental Assessment (EA) for the Pickering A "Return to Service",[5] which includes a probabilistic risk assessment (PRA) intended to:

- uncover all possible combinations of failures; and,
- get a better insight into the overall risk presented by the plants.

The PRA considers a comprehensive range of event sequences, and adds an analysis of frequency (probability of occurrence) and the time the safety system must operate to the design basis analyses, as well as accounting explicitly for the complex interactions between plant systems and human operators.

For a significant release of radioactivity to the environment to occur, there must be a release into containment together with an opening in containment and a driving force to expel airborne radioactive materials into the environment. The PRA process systematically searches for ways in which these three conditions can exist simultaneously. These theoretical releases are known as Ex-Plant Release Categories (EPRCs).

The calculated total risk (per station) for all EPRC events analyzed in the Pickering Nuclear Generating Station EA is reported to be 1.6×10^{-2} person Sv/y, which is approximately 1.5% of the operational collective dose calculated for 1998. When considering life cycle analysis, the relative

[5] Ontario Power Generation. *Pickering A – Return to Service Environmental Assessment. Volume 1: Main Report*. April 2000.

contribution from the EPRC events would be <1%. All future nuclear options will have a lower risk of a nuclear malfunction or accident.

Land: Land impacts can occur during various stages of the life cycle, including during extraction, processing, transportation, construction, operation and decommissioning. These impacts can include permanent alteration and consequent loss of species habitat. Land use impacts were adjusted on the basis of the potential for continued used. For example, in some instances the land around the facility may still be used for recreation, animal grazing or crop production.

Due to data constraints and the fact that many land impacts will be site-specific, land impacts associated with each of the life cycle stages were not available for this analysis. Each of the generation options has been evaluated in terms of the footprint of the plant, or of the reservoir created in the case of certain hydroelectric projects. Land impacts arising from other stages of the life cycle, for instance from mining or the construction of roads, have not been included.

Water: Water impacts can be related to consumption of water by a generating plant, or to water that is used and then returned to the original water body. The latter impact has been referred to as "withdrawal". Thermal and nuclear plants use water for cooling, either by using the water once and then returning it to the ambient water body, or continuously recycling the same water. When water is returned to the ambient water body, its temperature or chemical composition may have been altered, with potential consequences for aquatic biology and habitat.

Hydroelectric plants can be run-of-river, in which case all water is returned soon after withdrawal, with little impact. Hydroelectric plants can also involve the creation of a reservoir, which can have significant effects on hydrological systems, affecting water flows and levels, sediment quality and quantity, and aquatic biologic and habitat. Additionally, the creation of reservoirs can result in widespread flooding of land, negatively affecting local cultures and wildlife communities.

For each generation option, both the withdrawal and consumption of water have been measured in terms of volume per megawatt-hour.

Waste: Waste can be created during extraction, operation and decommissioning. SENES identified qualitative impacts associated with extraction, such as the creation of mine tailings, waste associated with processing ore, and liquid waste, such as pit water or in-situ leaching wastes. Because estimates of these impacts were not available for all generation options, they were not included in the quantitative analysis. Radioactive impacts associated with mining and processing have, however, been captured in the radioactivity category outlined above.

Depending on the fuel source, operational wastes can include combustion by-products such as ash and gypsum, radioactive waste, and hazardous wastes. These have been captured in the quantitative analysis, on the basis of tonnes of waste per megawatt-hour of generation.

Decommissioning waste was addressed qualitatively rather than quantitatively by SENES. With the exception of lead-acid batteries used for photovoltaic installations and nuclear waste, it is expected that most decommissioning waste would be recycled. Though quantitative impacts of decommissioning waste have not been assessed, radioactivity associated with nuclear decommissioning has been captured in the air emissions category.

Resource Availability: Renewability of the fuel source (in terms of estimated years of production remaining) was used as an indicative measure of how long production of electricity from various options could be sustained. Fossil fuels and uranium are finite resources that cannot be produced indefinitely. Water, wind, solar, and biomass are infinitely available if properly managed. However, an adjustment was made to take into account the fact that water resources are pressured by uses other than electricity, and because their availability is expected to be constrained by climate change.

2.6.5.4 Absolute and Scored Impacts

OPA presents the impacts associated with each portfolio in two ways – absolute impacts and scored impacts. Absolute impacts refer to the total physical environmental effects that are associated with a given portfolio over its lifetime. For example, absolute impacts include the total megatonnes of carbon dioxide equivalent emitted, or the total teralitres of water consumed.

These absolute impacts have been calculated using the life cycle data developed by SENES. The unit impact per megawatt-hour (or megawatt) for each environmental category has been input into the model simulation performed on each portfolio. Table 2.6.4 illustrates how the life cycle data for a single generating option (single cycle natural gas) for a single indicator category (greenhouse gas emissions) would be used.

Table 2.6.4 – Life Cycle GHG Emissions – Gas

Tonnes CO_2e/MWh					
Fuel	**60%**	**50%**	**40%**	**30%**	**20%**
	combined	combined	single	single	single
Natural Gas	0.29	0.35	0.44	0.59	0.88
Landfill Gas	0	0	0	0	0
Digester Gas	0.18	0.22	0.27	0.36	0.54

On a life-cycle basis, a single cycle natural gas plant operating at 40% thermal efficiency produces 0.44 tonnes of CO2e for every megawatt hour of production

Source: SENES and OPA

A single cycle natural gas plant operating at 40% thermal efficiency produces 0.44 tonnes of CO_2e for every megawatt hour of production. This information is included in the OPA's modeling, along with similar data for every generating option under consideration for every

environmental category. Based on the total energy and installed capacity of each generating option, the model calculates the total impacts in each category for each portfolio.[6]

While knowing the absolute impacts of each portfolio is useful, the question of how to compare impacts in each environmental category remains, such as a comparison of greenhouse gas emissions to water impacts to radioactivity. Not only are these impacts in different units, but social values concerning the relative dangers of each type of impact may vary. One way to get an overall picture of a portfolio and how it relates to others is to convert the category impacts to a common scale and then add them together to get an overall score.

SENES developed scores for each generation technology, based on a 0 to 10 scale. A technology with nil impact was assigned a score of 0, the worst performing technology was assigned a score of 10, with other technologies falling somewhere in between. Table 2.6.5 outlines the scores developed for the greenhouse gas indicator.

A score of 0 was assigned for impacts less than 0.01 tonnes of CO_2e per megawatt hour. Since the worst performing technology emitted at a rate of 1.14 tonnes CO_2e per megawatt hour, it was assigned a score of 10. All other technologies fall within the ranges between 0 and 10.

Table 2.6.5 – Global Warming Potential Scores

Score	Global Warming Potential (Tonnes CO_2e/MWh)
0	0-<0.01
1	0.01-0.15
2	0.16-0.30
3	0.31-0.46
4	0.47-0.61
5	0.62-0.76
6	0.77-0.91
7	0.92-1.06
8	1.07-1.21
9	1.22-1.37
10	1.38-1.52

A single cycle natural gas plant operating at 40% thermal efficiency produces 0.44 tonnes of CO2e for every megawatt hour of production, and would therefore be assigned a score of 3

Source: SENES and OPA

Taking the example noted above of a single cycle gas plant operating at 40% thermal efficiency – and producing 0.44 tonnes of CO_2e per megawatt hour – this type of plant would be assigned a score of 3. Each generation technology under consideration has been assigned a score for each indicator category. These scores are reported in Table 2.6.6.

[6] For details of the impacts associated with each option, see the SENES final report, Part 4.4. For the results for each portfolio, see Part 2.9.

2.6.5.5 Weighting Impacts

The Total Score for a portfolio is a weighted sum of the scores for each environmental category: contaminant emissions; greenhouse gases; radioactivity; land use; water use; waste; and resource availability. In order to add each of these scores together to form an overall total score for the portfolio, the relative weight of each category must be considered.

The European Commission has undertaken an exhaustive study, ExternE, on the life cycle impacts of different generating options and has monetized these impacts. Based on the monetized values, implicit weightings of the various impacts can be determined. In accordance with the SENES recommendations, OPA has used the following weightings, based on the ExternE study.

- Contaminant emissions = 10
- Greenhouse gases = 20
- All other categories, including radioactivity = 1

The above weighting values are an average of those reported in the ExternE reports for France and the Netherlands. The scores for each environmental category, and the total score reflecting the above weightings, are presented in Table 2.6.6 (below).

In order to determine the overall environmental score for a given portfolio, the percentage energy that is generated by a particular technology is multiplied by the Total Score for that technology. This concept can be illustrated using a hypothetical portfolio composed of three generating technologies.

Technology A: % of total portfolio (energy) x Total Score for Tech. A = Score A
Technology B: % of total portfolio (energy) x Total Score for Tech. B = Score B
Technology C: % of total portfolio (energy) x Total Score for Tech. C = Score C

Score A + Score B + Score C = Total Environmental Score for Portfolio

For example, if Technology A makes up 15% of the energy of a given portfolio, and is a 40% efficient single-cycle natural gas plant, Score A = 15% x 91 = 13.65. This procedure is carried out for each portfolio.

Some portfolios are associated with greater energy production than others, for instance, those that are designed to meet higher load growth. In general, greater energy production will be associated with larger environmental impacts. In order to account for these larger impacts, the environmental scores for the portfolios have been normalized on the basis of total energy produced.

Table 2.6.6 – Environmental Scores by Generation Type

		Contaminant Emissions (Weight = 10)	Greenhouse Gases (Weight = 20)	Radioactivity (Weight = 1)	Land Use (Weight = 1)	Water Impacts (Weight = 1)	Waste Impacts (Weight = 1)	Sustainability (Weight = 1)	**Total Impact (Weighted)**
Nuclear		1	1	6	1	4.5	1	5.3	**47.8**
Hydro									
	run of river	0	1	0	0	0	0	1	**21**
	reservoir/ impoundment	0	1	0	4	5.5	0	1	**30.5**
Hydro Import		0	1	0	8.5	5.5	0	2	**36**
Coal		5	7	10	1	3.5	10	2	**216.5**
Oil		5	10	1	1	5	3	5	**265**
Gasification									
	without CO_2 removal	4	6	10	1	2	0	2	**175**
	with 90% CO_2 removal	4	2	10	1	2	0	2	**95**
Natural gas									
	single cycle	2	3	0	1	2	0	8	**91**
	combined cycle	2	2	0	1	2	0	8	**71**
	fuel cell	Life cycle data unavailable							
Wind		1	1	0	4.5	0	0	0	**34.5**
Biomass		2	1	0	1	4	1	1	**47.0**
Photovoltaic		2	1	0	1	0	0	0	**41**

Note: Total Weighted Score is calculated by assigning of weight of 10 to contaminant emissions, a weight of 20 to greenhouse gases, and a weight of 1 to all other categories. Environmental scores for Hydro Import were based on values for the Manitoba purchase analyzed by SENES.

Source: OPA based on SENES data

2.6.6 Economic and Risk Analysis Methodology

This section describes the methodology used to determine the economic and risk parameters used in the portfolio simulations.

OPA has analyzed options both individually and collectively as portfolios.

- The individual option analysis ("LUEC analysis") is a simplified snapshot or average lifetime assessment of the options, with no consideration of interactions with other options.
- The portfolio analysis allowed for interactions between the options and existing resources in meeting load.

The screening analysis was based only on simplified assumptions – e.g. constant fuel costs and resource availability. However, sensitivity analysis was also performed to illustrate the range of uncertainty in the costs.

In the portfolio analysis, the operation of the Ontario power system over the period 2006-2025 was simulated. Simulation involves the selection of supply resources, hour-by-hour for the 20 year period, based on the marginal cost of the available resources. The Portfolio Screening Model (PSM), described in section 2.6.9, was used to carry out the simulations. Simulations were used for sensitivity analysis, as well as for the examination of alternative scenarios, and to produce probability distributions of key variables.

OPA looked at the costs of the supply options using different assumptions about the weighted average cost of capital (WACC).

The table below summarizes the differences between the perspectives and the data used.

Table 2.6.7 – Financial Parameters

WACC of 5%	WACC of 8.5%	WACC of 11%
Inflation Rate 2%	Inflation Rate 2%	Inflation Rate 2%
U.S.$ Exchange rate 0.85	U.S.$/Cdn$ Exchange rate 0.85	U.S.$/Cdn$ Exchange rate 0.85
Debt/Equity: 100/0	Debt/Equity: 70/30	Debt/Equity: 50/50
Cost of Debt 7% (nominal)	Cost of Debt 7% (nominal)	Cost of Debt 7% (nominal)
N/A	Cost of Equity 12% (nominal)	Cost of Equity 12% (nominal)
N/A	Tax Rate 36.1%	Tax Rate 36.1%
Weighted Average Cost of Capital (consistent with a public discount rate) 5% (real)	Weighted Average Cost of Capital (consistent with a public private partnership discount rate) 8.5% (real)	Weighted Average Cost of Capital (consistent with a commercial discount rate) 11% (real)

Source: OPA

The weighted average cost of capital was used as the discount rate to bring future costs to their present value, and to determine annuity factors in the LUEC calculations.

In Table 2.6.8, the income statement for the investor is developed by:

- Adding the fixed and variable operating expenses and depreciation (an expense to the investor, but not one considered in the portfolio analysis)

- Adding to this interest expense – which is 7% of the 50% of capital costs assumed to be debt-financed
- Calculating earnings before tax: 18% (the pre-tax WACC) of the 50% of the cumulative equity
- Calculating current income tax: 36% of the above earnings before tax
- Calculating final revenue requirement (i.e. total revenues) is calculated by adding the above costs to earnings before tax.

The revenue requirement is a pre-tax cash flow and is therefore discounted by a pre-tax WACC.

Table 2.6.8 – Illustrative Income Statements

Illustrative Income Statement	2006
Revenue	
Revenue Requirement	9,071,962
Operating Expenses - Variable	
Dispatch Expense	3,931,218
Operating Expenses - Fixed	
Fixed O&M	1,475,722
EBITDA	3,665,022
Book Depreciation	1,090,022
Interest Expense @ 7% Pre-tax Cost	700,000
Earnings Before Tax (18%)	1,875,000
Current Income Tax	675,000
Net Income @ 12% After Tax Return	1,200,000

WACC Pre-Tax

	Return	Weight
Equity	18%	50%
Debt	7%	50%
Nominal WACC	13%	
Less Inflation	2%	
Real WACC	11%	

Must earn 18% on equity pre-tax to be equivalent to 12% after tax

WACC After Tax

	Return	Weight
Equity	12%	50%
Debt	4%	50%
Nominal WACC	8%	
Less Inflation	2%	
Real WACC	6%	

Source: Navigant Consulting Inc.

Under both societal and commercial perspectives, the risks around the costs were assessed. The process/methodology used by OPA has four main steps:

- A screening analysis of the options based on economic, risk and environmental impacts (described in Part 2.7).
- Development of alternative scenarios
- Development of portfolios representing alternative policy choices within each scenario (scenarios and portfolios are described in Part 2.8).

- Scenario/sensitivity analysis (results are described in Part 2.9).

The methodology and assumptions used in the screening analysis and portfolio analysis are described in the following two sections.

2.6.7 Screening Analysis

The costs of the options have been compared using their levelized unit energy costs. Levelized Unit Energy Cost (LUEC) is a cost measure that allows comparison of options with similar operating regimes. Various options may have different patterns of expenditures, service lives and sizes. One option may be expensive to build but cheap to run compared to another option which is vice versa. LUEC is consistent with, but not a substitute for the more detailed measure, the Present Value Revenue Requirement (PVRR). It is a single number expressed in ¢/kWh or $/MWh, and can be expressed in constant dollars or escalated dollars.

The LUEC methodology levelizes costs by an annuity method which involves allocating costs in equal annual instalments over the operating life of the option in such a way as to give the same cumulative present value as the original expenditures.

2.6.8 Scenario and Portfolio Development

Comparing individual options in terms of their individual costs through LUECs (as described in the previous section) and environmental impact does not recognize the complexity of the power system. The operation of generation resources is highly interactive, and analysis of a single resource at a time can give misleading or incomplete answers.

The object of the supply mix study is to find a portfolio of options that is robust, both in terms of interactions among existing and new options, and in light of future uncertainties.

To be rigorous in the analysis it is necessary to simulate the operation of the power system year by year into the future and consistent with the parameters of each scenario. Alternative future developments of the system are developed to allow for the examination of different policy choices. The combination of resources and their associated in-service dates is called a portfolio. Each portfolio is designed to meet load growth with the appropriate reserve margin so as to provide a reliable electricity supply in the face of an uncertain future. The scenarios considered and the portfolios developed are described in section 2.8.

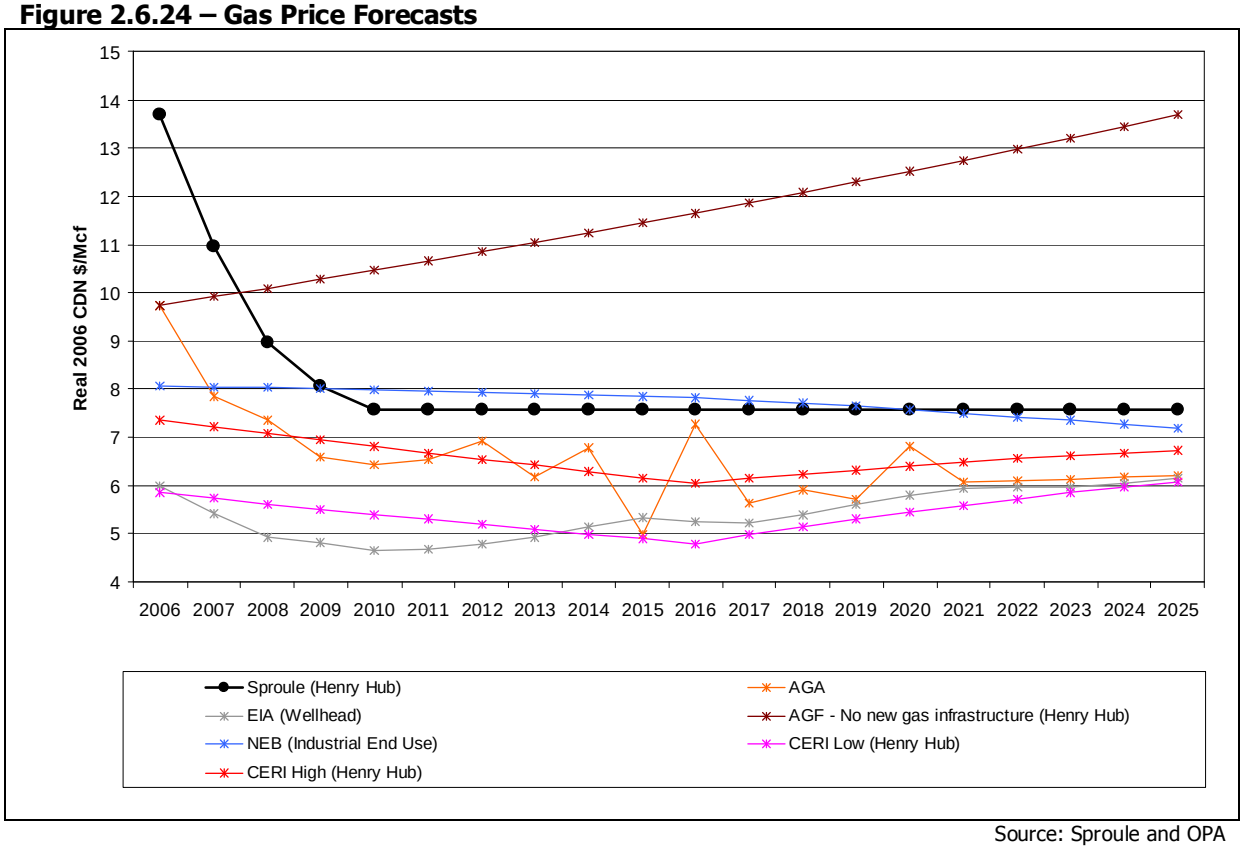
2.6.8.1 Portfolio Simulation

To determine the cost of running the power system in the future with the alternative portfolios, the Portfolio Screening Model (PSM) developed by Navigant Consulting Inc. (NCI) was used (described in detail Part 4.1). PSM allows simulation of the generation system over the next 20 years, and provides cash flows, revenue requirements, and environmental emissions year by year. The model has the ability to be run either deterministically, assuming that all parameters are known with certainty, or stochastically, putting uncertainty ranges around key parameters. The model then determines the probability distribution of costs, revenues, and emissions.

The cost data used in the model for the individual options are described in section 2.7. The gas price forecast used was produced by Sproule, for the Henry Hub, with a suitable adder for delivery to Ontario. Further discussion of gas supply and price issues can be found in Part 3.9. NCI's report, Part 4.1, gives details of other price forecasts used.

The Sproule forecast, together with other forecasts, is shown in Figure 2.6.24.

Figure 2.6.24 – Gas Price Forecasts



Source: Sproule and OPA

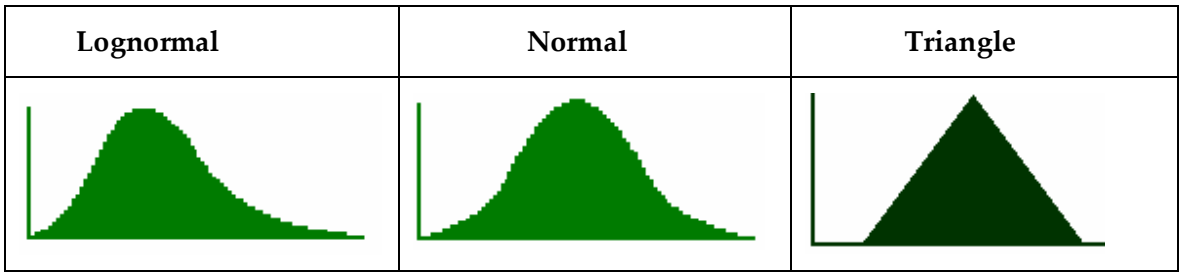
Variabilities were simulated in the following items:

- Commodity prices: natural gas, coal, oil and uranium
- Forced outage of generation units including capital cost
- Load variability due to weather

- Hydrology (the amount of water for generation at hydroelectric generating stations)

Part 4.1 details how the probability distributions for these variables were determined, and how they were simulated in the model. Figures 2.6.25 to 2.6.28 summarize the approach and assumptions used.

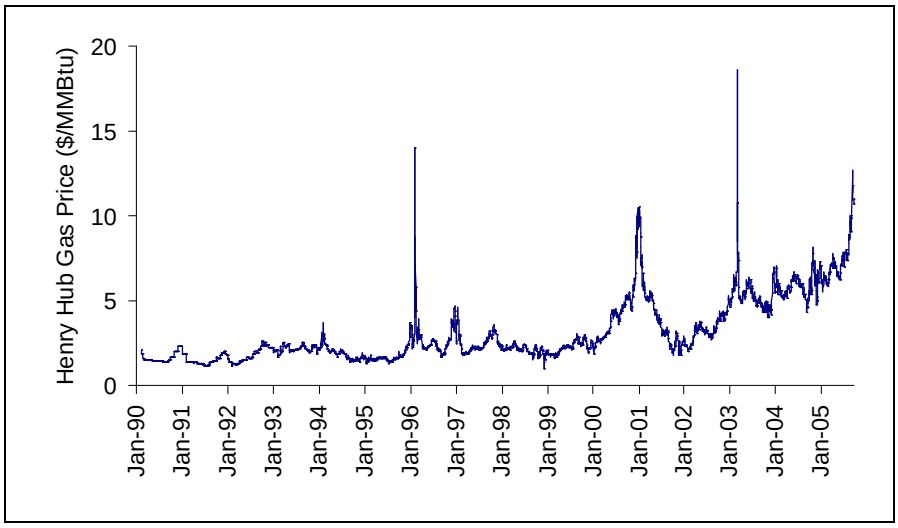
Figure 2.6.25 —Distribution Types



Source: Navigant

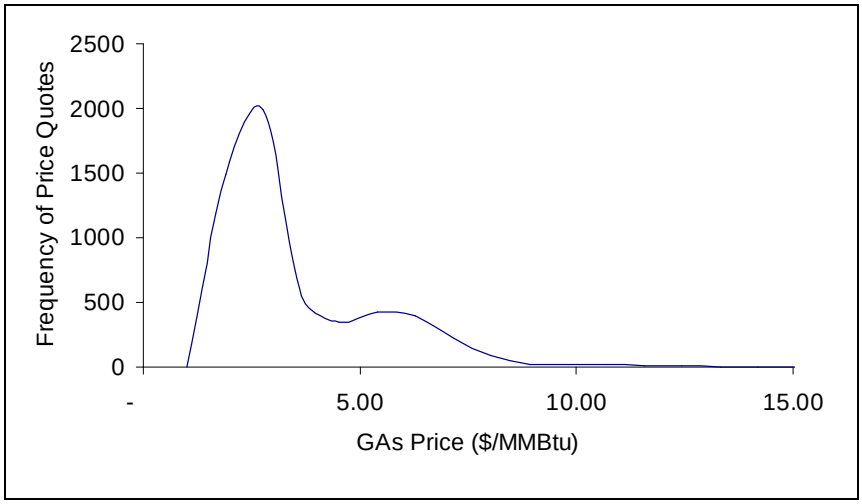
Of particular interest is natural gas volatility, which can be observed in the figures below, first as a time series, and second as a frequency distribution.

Figure 2.6.26 – Historical Natural Gas Price (Henry Hub)



Source: NCI

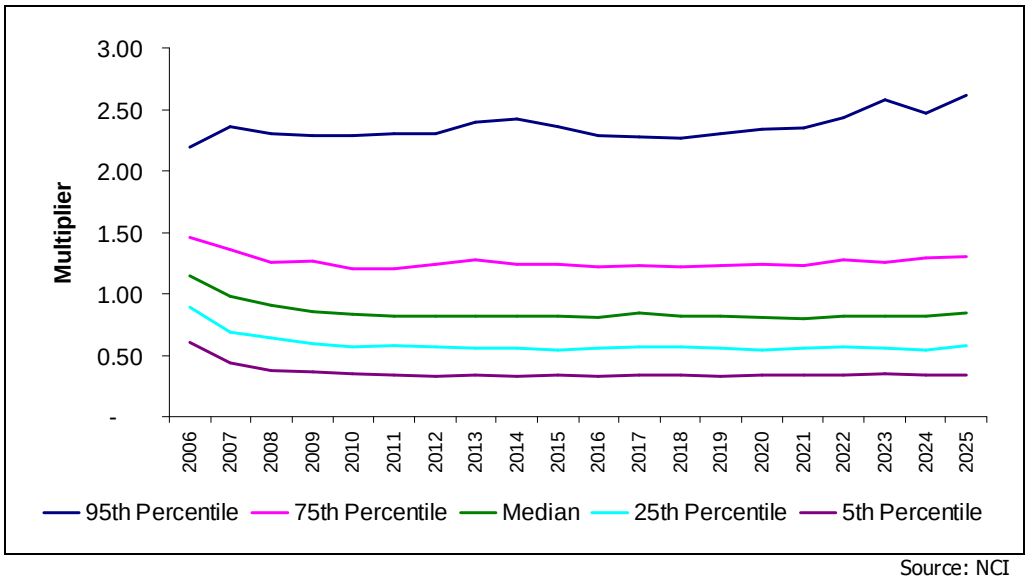
Figure 2.6.27 – Frequency of Price Observations



Source: NCI

The frequency distribution was approximated to a log-normal distribution. When applied to the forecast of gas prices, the following confidence bands were observed.

Figure 2.6.28 – Natural Gas Volatility Multipliers



Source: NCI

With a gas price forecast in the $8/MMBtu range, the 90% range for price volatility is between $3.20 - $20.00/MMBtu.

Some uncertainties cannot have probabilities assigned to them. In such cases, sensitivity studies were needed. These could be run, in the PSM, either deterministically or stochastically. Sensitivity studies were done deterministically to examine the impact of:

- Higher carbon dioxide mitigation costs
- Higher gas prices together with higher carbon dioxide mitigation costs
- Lower nuclear capital and refurbishment costs
- Lower gas prices
- A higher discount rate

The effect of climate change on hydrology variability was studied stochastically.

In addition to these sensitivities, two combinations of sensitivities were examined. The first, labeled "climate change", illustrates a combination that might arise when climate change is fully recognized. In this combination, it was assumed that there would be less water available for hydroelectric generation (70% of base), the cost of greenhouse gas mitigation would be doubled and, with a booming nuclear industry worldwide, the cost of nuclear power would be reduced (70% of base).

The second combination looked at possible technology cost improvements, driven by higher fuel costs. In this combination, fuel cells and wind capital costs drop by 30%, and gas prices average $10/MBtu. Neither the composition of the portfolios nor the load was changed in these combinations of sensitivities.

2.7 What Are the Available Resources and Their Impacts?

This chapter examines the characteristics of the various supply and demand options analyzed by OPA to address the challenge presented in Part 2.5. Characteristics addressed include those of the technologies themselves, costs, and environmental impacts. This is only a brief summary. Additional details are found in volume 4, particularly the consulting reports from CERI and SENES. A brief discussion of distributed generation is included, but the more complex issues associated with incorporation of distributed energy are only generally addressed.

2.7.1 Key Findings

- Levelized unit energy cost (LUECs) are an important overall measure of the cost of an option; a summary measure of the average cost of electricity per kilowatt-hour expressed in current dollars or dollars of a specified year
- LUECs are commonly used in studies for comparing the cost of power from competing technologies
- LUEC is defined as the price of electricity output required by a plant to recover exactly the net present value of all capital, operation and maintenance, fuel, and decommissioning costs expected to be incurred over its economic life
- Environmental characteristics are generally grouped by contaminant emissions, greenhouse gases, radioactivity, land use, water withdrawal and consumption, waste and resource availability.
- The life-cycle environmental impact of renewable generation technologies is less than that of both nuclear and fossil fuel generation. Using the weighting of environmental categories recommended by SENES, nuclear generation performs better than fossil fuel generation, including combined cycle natural gas and gasification with sequestration of carbon dioxide.
- Technical performance of various supply technologies are assessed with respect to costs, and environmental loading (air, land, water and waste impacts)
- cost and environmental characteristics for a range of supply options and technologies are examined

2.7.2 Introduction

An important overall measure of the cost of an option is its levelized unit energy cost (LUEC), which is commonly used in studies for comparing the cost of power from competing technologies. The LUEC is a summary measure of the average cost of electricity per kilowatt-hour expressed in current dollars or dollars of a specified year. The LUEC is defined as the price

of electricity output required by a plant to exactly recover all capital, operation and maintenance, fuel, and decommissioning costs expected to be incurred over its economic life. In this section the levelized costs are calculated using various discount rates. They are also described as different weighted average costs of capital (WACC), we use the terms interchangeably because the detailed simulation model, portfolio screening model uses WACCs while the LUEC calculations used discount rates. The net result in comparing options is similar and depends on whether we are screening option using LUECs or simulating an integrated plan using portfolio screening model.

Environmental characteristics are generally grouped by contaminant emissions, greenhouse gases, radioactivity, land use, water withdrawal and consumption, waste and resource availability.

2.7.3 Hydroelectric

2.7.3.1 Overview

Hydroelectricity is the most important source of renewable energy in Canada, accounting for about 11 percent of total primary energy and over 60 percent of electricity generation. In 2003, hydroelectricity also contributed approximately 60 percent of Canada's net electricity exports of 6.6 TWh.

Hydroelectricity is generated by the force of water as it falls into turbines and rotates the shaft, converting the potential energy of the water into kinetic energy (energy in the form of motion). The amount of energy available depends on the height the water falls ('head") and the volume of water passing through the turbines. Hydroelectric generating plants can "store" energy (by raising the height of the upstream reservoir) and then release water to generate electricity when it is needed. This ability to store energy is an asset that can be combined with other renewable technologies such as wind energy to enable larger scale use of renewable energy.[1]

Today's hydroelectric power plants range in size from small, local projects producing a few kilowatts to huge dams and reservoirs that generate 10,000 MW. Hydroelectric power plants that generate up to 100 kW of electricity are called "micro hydro". Hydro plants that generate between 100 kW and 30 MW are called "small hydro power".

Although many hydroelectric power installations use conventional storage in upstream reservoirs, pumped storage may also be used to capture unused electricity during times of low use. In this mode, water is pumped through a reversible turbine, from a lower reservoir to an upper reservoir during off-peak hours when electricity costs are lowest. Then the water flow is reversed during times of high electrical demand to produce electricity. Water is generally

1 US Department of Energy: http://www.energy.gov/engine/content.do.

pumped back to the upper reservoir at night and on weekends. Pumped hydro is available at almost any scale with discharge times ranging from several hours to a few days.

2.7.3.2 Performance Characteristics

Hydroelectric generation is a mature technology that has not been overtaken by invention over time. The efficiency rate of hydroelectric plants is generally two times greater than that of fossil-fuelled plants. Hydro power stations have a long life and many existing stations have been in operation for more than half a century and are still operating efficiently.[2]

Generating electricity from water sources is cheaper than other technologies because fuel costs are minimal. Moreover, hydroelectric plants have low maintenance costs, and do not need many workers to operate them. On the downside, however, the output of hydro power plants depends on water availability, which means that during drought periods, less electricity will be produced.

Hydroelectric power stations have the ability to respond within short periods to changes in demand. This flexibility characteristic enhances their value to the supply mix and to the diverse needs of different consumer classes in general.
Over the period 1999-2003 in Canada the probability that a hydroelectric unit would be unavailable if needed was 1.7 percent.

2.7.3.3 Costs

There are economies of scale that favour large hydroelectric power projects over small ones. That is, capital costs per kWh generally decrease with increasing scale. However, the combination of a long lead time, uncertain growth in demand for electricity and price, and uncertainty in the total cost of financing construction increase risks for larger projects. Very large projects that must effectively be built as a single large plant (e.g., a very large hydro dam) are more vulnerable to this type of risk than projects for which development can be phased in as several smaller power plants.

Illustrative costs for hydro-electric generation are outlined in Table 2.7.1. It is recognized that hydroelectric costs are highly site specific and therefore may vary. Illustrative levelized unit energy costs are presented in Table 2.7.2, both from a social and commercial perspective.

Table 2.7.1 – Illustrative Costs: Out-of-Province Firm Purchase

	$ / MWh	$ / kW		
	Variable O & M	**Fixed O & M**	**Capital Cost**	**Ongoing Capex**
Hydroelectric	0	40.83	2,666	2.30

Source:OPA

2 http:www.canren.gc.ca

Table 2.7.2 – Illustrative Levelized Unit Energy Costs: Hydroelectric

LUEC at 5% WACC ($/MWh)	50.7
LUEC at 11% WACC ($/MWh)	99.9

Source: OPA

Key assumptions made in calculating the above LUECs are as follows:

- Social discount rate 5% (real)
- Debt/Equity ratio of 50/50
- Rate of return on equity 12% (nominal)
- Cost of debt 7% (nominal)
- Tax rate 36.1%
- Inflation rate 2% per year
- Weighted average cost of capital (commercial discount rate) 11% (real)
- Capacity Factor: 45%

2.7.3.4 Environmental Characteristics

The environmental evaluation of hydroelectric generation options involved a number of assumptions. The first involved the definition of hydroelectric generation type. With respect to hydroelectric generating stations, there are three basic types:

- Impoundment – generation involving the installation of a dam (assumed to be made from concrete) and creation of a reservoir including some amount of flooding. Water release for generation may be based on demand (peaking operation) or for the maintenance of the water level downstream
- Pumped storage – water is pumped from a lower reservoir to an upper reservoir based on energy demand. This type of station does not always involve the creation of a dammed reservoir
- Diversion – water is not impounded into a reservoir; instead, it is diverted from the natural water course and passes through some form of channel and then through the turbine

It was decided that with respect to potential environmental impacts, the largest difference between hydroelectric stations was not by the size, and, therefore, megawatts of electricity produced, but rather by type of station. In particular, environmental impacts were most influenced by whether or not a reservoir would be created. The assumption was also made that there would be no cascading system effects arising from the installation of a number of stations along the same watershed

Contaminant Emissions: There are no atmospheric emissions from the hydroelectric generation itself, though some contaminant emissions are released during construction of the dam.

Greenhouse Gases: Activities associated with the construction of the dam also result in carbon dioxide emissions (CO_2) primarily due to manufacture of the concrete used in the dam. Flooding practices can result in methane emissions due to decomposition of vegetation within the flooded reservoir.

Land Use: For the three styles of hydroelectric generation, impoundment will result in the largest impacts to land use. Diversion stations should result in little or no impacts, except potentially from access road construction – which is site specific, and therefore not included in this analysis. A pumped storage facility may or may not result in the creation of one or more reservoirs. However, the exact details of land impacts caused by pumped storage hydroelectric generation is again site specific and cannot be generalized.

Land use estimates for impounded hydroelectric generating stations were based primarily on the size of the reservoir created for the station.

Water Use: Hydroelectric stations have very high amounts of water flow through the turbines in a given year. Typically, this value is equal to the entire volume of water that passes down the particular system. However, while the impacts of this water use may be significant, the impacts associated with hydroelectric stations are entirely different in character from those at thermal or nuclear generating stations.

In particular the water typically does not undergo any physical quality impacts, with the exception of dissolved oxygen impacts associated with supersaturation during spilling or when air is used in the turbines to avoid mechanical stress. However, supersaturation impacts can be mitigated. Of much more importance is the sometimes drastic changes to the regional hydrograph,[3] downstream wetted area and reservoir elevations. It is the estimation of water volume impacted by these effects that must be evaluated for hydroelectric generation.
The final water use effect from hydroelectric generation considered for this project is changes in the reservoir elevation. For any given hydroelectric station, reservoirs are typically operated in a range of reservoir elevations. Typically this range is a few meters. These changes generally occur over the course of an operating year, although they may occur on much shorter time scales such as monthly to even weekly, and are typically planned in consultation with provincial water authorities.

Although these fluctuations are typically less biologically damaging than drastic changes to the downstream wetted area, reservoir elevation levels are not typically mitigated (although they are often regulated). Further, although considerable assumptions must be made, these fluctuations provide for a number that is estimable as a litre per megawatt impact.
For the purposes of this document, it will be assumed that pumped storage facilities have the same impacts as impounded reservoirs. Diversion facilities, as defined for the purposes of this

[3] A hydrograph is a visual representation of the changes in flow or level of a water body over time.

document will not have water use impacts because they simply pass a portion of the water and return it. Therefore, from diversion hydroelectric generation, impacts to downstream or upstream flow are minimal.

Waste: There are no waste products requiring storage or disposal as a result of routine operation of a hydroelectric station.

Resource Availability: Hydroelectric energy is a renewable energy source and is the main source of electricity in Canada. However, water – particularly freshwater – receives pressure from other sources, and availability may be reduced due to expected climate change impacts.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the hydroelectric option.

Table 2.7.3 – Life Cycle Air Impacts – Hydroelectric

	Kg / MWh							Sv / GW - year
	NO_x	SO_2	PM_{10}	$PM_{2.5}$	HAPs	Contaminant Emmissions	CO_2e	Radioactivity
Run of River	0.03	0.04	0.003	0.003	-	0.07	20	0
Reservoir/ Impoundment	0.03	0.04	0.003	0.003	-	0.07	33	0

Source: OPA, SENES

Table 2.7.4 – Life Cycle Land, Water and Waste Impacts – Hydroelectric

	Km^2 / MW	Water Use L / MWh		T/MWh
	Land Use	Withdrawal	Consumption	Waste
Run of River	0	0	-	0
Reservoir/ Impoundment	0.0935	270500	-	0

Source: OPA,SENES

Table 2.7.5 – Scored Environmental Impacts – Hydroelectric

	Contaminant Emissions	CO2e	Radioactivity	Land Use	Impacts		Resource Availability	Total Impact (Weighted)
					Water	Waste		
River of River	0	1	0	0	0	0	1	21
Reservior/ Impoundment	0	1	0	4	5.5	0	1	30.5

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.4 Out-of-Province Purchases

2.7.4.1 Overview

Both the Ontario-Manitoba Interconnection (OMI) project and the Churchill Falls development in Labrador are potential long-term firm purchase options for Ontario. For present purposes, cost, performance and environmental performance analysis were based on OMI.
Manitoba and Ontario are in discussion for a long-term purchase of 1500 MW to 3000 MW beginning as early as 2012 from a new hydroelectric development at the Conawapa site on the Nelson River in northern Manitoba. This purchase would require significant new 500 Kv transmission infrastructure to deliver the power to Ontario. The provinces will continue to work with the federal government on financial support for the project, which would contribute to meeting Canada's Kyoto commitments.

A second potential major purchase involves a joint proposal with Hydro-Québec and SNC-Lavalin to support Newfoundland and Labrador in the development of a major hydroelectric generation project at the Lower Churchill River. The proposed project would yield 2,824 megawatts, of which Ontario would receive one-third of the total output of the project (941 MW).

2.7.4.2 Costs

Illustrative costs for a firm out-of-province purchase are outlined in Table 2.7.6. Illustrative levelized unit energy costs are presented in Table 2.7.7, from Weighted Average costs of capital (WACC) of 5% and 11%.

Table 2.7.6 – Illustrative Costs: Out-of-Province Firm Purchase

	$ / MWh	$ / kW		
	Variable O & M	Fixed O & M	Capital Cost	Ongoing Capex
Firm Purchase	0	42.35	4550	2.35

Source:OPA

Table 2.7.7 - Illustrative Levelized Unit Energy Costs: Out-of-Province Firm Purchase

LUEC at 5% WACC ($/MWh)	67
LUEC at 11% WACC ($/MWh)	117

Source: OPA

A capacity factor assumption of 60% was made in calculating the above LUECs. Financial assumptions are the same as those in section 2.7.3.3.

2.7.4.3 Environmental Characteristics

The environmental characteristics of a transmission line are significantly different than that of a generating station. In the case of the proposed Ontario-Manitoba Interconnection (OMI) project, land, water and air impacts will occur over a distance of more than 2,000 kilometres, while the natural environmental impacts of a generating station are primarily local (with the exception of dispersion of air emissions and upstream/downstream effects of water use). Because a new generation station will be required on the Nelson River to support the transmission line, the environmental impacts of this station must be factored into the total environmental impact of the OMI Project.

Natural environmental impacts of a high voltage transmission line occur during construction (right-of-way clearing, constructing access roads, preparing the tower foundations, tower assembly and stringing the conductors), operation (right-of-way maintenance, EMF issues) and decommissioning (tower disassembly and removal). They fall into the same general categories as the generation options and the magnitude of the impact tends to increase with the length of the line.

In terms of a life-cycle assessment, the raw materials that create a transmission tower are similar to those found in a tower used for wind power generation. The number of transmission towers, however, in over 2,000 kilometres is difficult to predict since this will depend upon system design (AC versus DC, average span, topography, etc.). There could be well over 3,000 towers, depending upon various engineering considerations.

EMF Emissions: A 2002 publication by the National Institute of Environmental Health Sciences and the National Institutes of Health in the U.S. surveyed research on EMF exposure to humans in various countries around the world. In general, no link between high voltage electric transmission facilities and health issues has been substantiated.

In December, 1998, a working group of public health officers at Health Canada issued a review of the scientific literature regarding power-frequency EMF health effects. It found the evidence to be insufficient to conclude that EMF causes a risk of cancer (NIEHS, 2002).[4] The live power lines are well removed from human contact. With proper training in working around power lines, maintenance workers rarely experience burns or fatalities.

Land Use: The actual land (footprint diameter) required for a tower ranges from 30 metres for a V-guyed 500 kV DC tower to 36 metres for a similar AC tower, while the width of the cleared right-of-way required ranges from 70 to 80 metres. The land requirement for the transmission line would thus be roughly 150 square kilometers of cleared land (for a 2,000 km line). Since most of the land is forested, it would result in the destruction of a great deal of natural habitat

[4] National Institute of Environmental Health Sciences and the National Institutes of Health (NIEHS). EMF questions and Answers. NIS Publication 02-4493, 2002.

and the permanent removal of the forest cover from the right-of-way, taking it out of production and thus affecting forest sustainability.

Land use estimates for the OMI project must include both those for the transmission line interconnection between Manitoba and Ontario and also the land use estimate for the generation station itself. However, because the exact land use estimate for the hydroelectric generation station that will supply power for the OMI project is not known, the estimated impacts are based on the range of values found for impounded hydroelectric generation stations. The values for land use for transmission and generation are then summed to provide an overall estimate for land use values.

Water Use: Although the OMI project is likely to cause some impacts to water bodies during construction because of water crossings, these impacts are site specific and would require full mitigation. Therefore, OMI water use impacts are restricted to those resulting from generation, which are estimated in the hydroelectric generation analysis portion of this section.

Resource Availability: For the OMI, apart from the hydroelectric generation portion, the resource that is really being utilized is land. In Canada, the argument could be made that land is essentially infinite in abundance; however, there are areas of Canada, particularly in the southern halves of all provinces, including Ontario, where land is a limited resource. Therefore, it was determined that for this project, land would be considered a finite resource. The task became determining how many "years of production" remained in Ontario for a project the size of the OMI.[5]

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the inter-provincial purchase option. Impacts include those arising from the generation plant and the transmission line.

Table 2.7.8 – Life-Cycle Air Impacts – OMI

	kg/MWh							Sv/GW-year
	Nox	SO2	PM10	PM2.5	HAPs	Contaminant Emissions	CO_2e	Radioactivity
OMI	0.03	0.04	0.003	0.003	-	0.07	33	0

Source: SENES and OPA

Table 2.7.9 – Life Cycle Land, Water and Waste Impacts – OMI

	km^2/MW	L/MWh		T/MWh
	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
OMI	0.22	270500	-	0

Source: SENES and OPA

[5] For details regarding SENES approach to determining the remaining "years of production" for the OMI project, see Part 4.4, p.p. 7-53 to 7-54.

Table 2.7.10 – Life Cycle Scored Environmental Impacts – OMI

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
OMI	0	1	0	8.5	5.5	0	2	**36**

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.5 Wind

2.7.5.1 Overview

Wind power is a renewable source of electricity generation that is increasingly attracting the interest of policy makers.

Electricity can be generated by transforming the kinetic energy of the wind using turbines. There are two fundamental styles of electric wind turbines: horizontal axis or vertical (egg beater style) axis designs. The horizontal axis design has proven to be more efficient on a number of dimensions. Consequently, the global commercial market almost exclusively uses horizontal axis turbines.

The key components of a wind turbine are:

- blades, or a rotor, which translate the wind's kinetic energy into rotational shaft energy
- an enclosed space called a nacelle, that includes a generator, a gearbox[6] and a drive train
- a tower, to hold up the drive train and rotor, and
- electronic equipment such as controls, electrical cables, ground support equipment, and interconnection equipment.

Wind turbines are designed to produce high quality, network frequency electricity whenever enough wind is available. Current generation turbines typically use three blades, with their speed and power controlled by either pitch or stall regulation. The most common regulation is pitch; it entails changing the angle of the blades. In contrast, stall regulation entails controlling the mechanical rotation of the blades.

The blades are made from composite materials using fibreglass with either epoxy or polyester, at times in a blend with carbon and wood. The kinetic energy of the blade rotation is transmitted to an electrical generator by way of a gearbox and drive train. Otherwise, the generator can be linked directly to the blades using a "direct drive" configuration.

[6] Some turbines operate without a gearbox.

Current technology permits turbines to operate at varying speeds, facilitating integration with the electricity grid. The nacelle encloses the gearbox, generator, and other control equipment. Tubular towers hold up the blades and nacelle. Both the nacelle and rotor are able to shift or "yaw"; a feature that allows for favourable positioning against the prevailing wind.
Current generation turbines are far superior to their predecessors built in the 1980s when the manufacture of commercial wind turbines began in earnest. At the time, Danish technology dominated, producing 20-60 kilowatts (kW) turbines with blade diameters of around 20 metres (m). Since then, wind turbine generators have increased in capacity to 2 megawatts (MW) and above, with blade diameters of 60-90 m. The largest turbine currently in production has a capacity of 4.5 MW and a rotor diameter of 112 m.

The efficiencies of turbines have increased dramatically through the following improvements: more powerful rotors, larger blades, improved power electronics, better use of composite materials and taller towers. Land use is saved since it now takes fewer turbines to generate electricity at a given rate. The power generated by wind turbines has increased more than 200-fold since the early 1980s. Recently, larger turbines, in the 1.5 to 2.5 MW range, have more than doubled their global market share from 16.9 percent in 2001 to 35.3 percent in 2003.

2.7.5.2 Performance

The principal performance drivers of wind power economics are electricity production (dependent on average wind speed) and the turbine lifetime. Site selection is crucial for attaining economic viability as electricity production is highly dependent on wind conditions. A 1 MW turbine, depending on wind conditions at its site, can produce sufficient electricity for up to 650 households.

Wind resource characteristics have a significant effect on the commercial value of a site. The electrical power from wind increases with the cube (third power) of the wind speed; therefore small changes in average wind speed can create substantial variation in performance. A doubling in wind speed, from say 6 to 12 m/s, will therefore lead to an eight-fold increase in power output.
Wind power development requires comprehensive and dependable information about a site's wind resource characteristics including: the strength, regularity, and directionality of wind. The wind resource is measured by a classification that increases according to average wind speed.[7] Class 4 (and above) wind power sites are characterized by average wind speeds higher than 7 m/s and are considered to be commercially viable in Ontario with tax and market incentives. Class 7 sites have average wind power over 8.8 m/s are considered competitive with all electricity generation sources.

Wind is intermittent by nature and the actual electricity generated by a turbine, measured by the capacity factor, will vary accordingly. The average annual capacity factor of modern land-

[7] Wind sites are ranked from Class 1 to Class 7. Class 1 is for sites with average wind speeds less than 5.6 m/s.

based wind turbines will vary from 25 to 40 percent.[8] A recent study by the Canadian Wind Energy Association (CanWEA) found that in Ontario the capacity factor experiences seasonal variation as winds are typically stronger in the winter (capacity factor rises to a high of 47 percent) than in the summer (capacity factor drops to a low of 19 percent).[9]

The intermittent nature of wind creates balancing issues for the system operator; a secondary source of generation is required for those times when the wind is not blowing. The need to balance off electricity is mitigated substantially if wind generation assets are geographically dispersed. The aforementioned CanWEA study suggests that an additional 200 MW of wind would require only 37 MW of balancing generation. Recent improvements in forecasting the energy output from wind farms have also diminished system integration issues.

Wind turbines have a design life of 20 years; they can run continuously, unattended and with low maintenance with some 120,000 hours of active operation. The operating availabilities of wind turbines, the percentage of the time they are available for operation, is extremely high at 98 percent. Among electricity generating technologies, wind turbines have the highest reliabilities.

Once a wind farm is constructed and operational it can be supervised and managed at a distance. A mobile crew performs maintenance; approximately two workers are needed for every 20 to 30 turbines. A current generation wind turbine requires about 40 hours per year of maintenance.

2.7.5.3 Costs

Illustrative costs for a wind generation are outlined in Table 2.7.11. Illustrative levelized unit energy costs are presented in Table 2.7.12, both with WACCs of 5% and 11%.

Table 2.7.11 – Illustrative Costs Wind

	$/MWh	$/kW		
	Variable O&M	Fixed O&M	Capital Cost	Ongoing Capex
Wind	0.00	46.69	1,912.97	1.15

Source:

Table 2.7.12 – Illustrative Levelized Unit Energy Costs: Wind

LUEC at 5% WACC ($/MWh)	67.8
LUEC at 11% WACC ($/MWh)	102.9

Source: OPA

[8] "The Most Frequently Asked Questions About Wind Energy" by American Wind Energy Association (AWEA) http://www.awea.org/pubs/documents/FAQ2002%20-%20web.PDF.
[9] "An Analysis if the Impacts of Large-Scale Wind Generation on the Ontario Electricity System", CanWEA.

A capacity factor assumption of 30% was made in calculating the above LUECs. Financial assumptions are the same as those in section 2.7.3.3.

2.7.5.4 Environmental Characteristics

Aside from the raw material and energy cost associated with the production of turbine components, wind energy is considered to be pollution free and infinitely sustainable. The operation of wind turbines does not create greenhouse gases and/or produce toxic or radioactive waste.

While there are no emissions associated with the operation of wind turbines, there are some contaminant and greenhouse gas emissions created during the manufacturing of materials for construction, and construction activities themselves.

Wind generation does not involve any appreciable water use. Water impacts may be present during construction in the form of water crossings by access roads. However, these impacts are site-specific and would be mitigated during the project environmental assessment.
There are no waste products requiring storage or disposal as a result of routine operation of a wind farm.

Land Use: Wind farms require a relatively large amount of land, however, much of this land may still be suitable for human or biological use. For example, land between turbines can still be utilized for animal gracing or crop production.

Quantified Environmental Impacts

The following tables summarize the environmental impacts of the wind option.

Table 2.7.13 – Life Cycle Air Impacts – Wind

	Kg / MWh							Sv/GW-year
	No_x	SO_2	PM_{10}	$PM_{2.5}$	HAPs	Contaminant Emissions	CO_2e	Radioactivity
Wind	0.042	0.06	0.029	0.02	-	0.15	12	

Source: SENES and OPA

Table 2.7.14 – Life Cycle Land, Water and Waste Impacts – Wind

	km^2/MW	L/MWh		T/MWh
	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
Wind	0.125	0	0	0

Source: SENES and OPA

Table 2.7.15 – Scored Environmental Impacts – Wind

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
Wind	1	1	0	4.5	0	0	0	34.5

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.6 Biomass

2.7.6.1 Overview

Biomass includes residues from agriculture, forestry, pulp and paper plants, and waste from the manufacturing, commercial and residential sectors, including landfill and sewage waste. Biomass is also available from peat deposits and dedicated energy crops. It can be burned, gasified, pyrolyzed, or converted to bio-oil. Each of these processes enables biomass to be used as a fuel for generating electricity and heat.

Combustion: Biomass can be fired in a burner to create steam in a boiler which drives a turbine and generator set. This technology is very similar to that currently used in conventional thermal plants. In fact, many coal-fired power plants have begun co-firing biomass with the coal as a means of reducing air emissions; however thermal biomass plants also operate using biomass alone. Often the biomass is dried and compressed prior to being fired in the burner. Heating values for biomass are significantly less than those for high quality coal.

Gasification: Biomass gasification is a thermal conversion process where a solid fuel is converted into a combustible gas. The process of gasification is similar to that of coal gasification. A limited supply of oxygen air, steam or a combination serves as the oxidizing agent. The product gas consists mainly of carbon monoxide, carbon dioxide, hydrogen, methane, water, nitrogen and contaminants including small char particles, ash and tars. After cleaning the gas it is suitable for boiler, engine and turbine use to produce heat and power.

Pyrolysis: When biomass decomposes at elevated temperatures in a process known as pyrolysis, three primary products are formed: gas, bio-oil and char. At high temperatures the bio-oil vapours are decomposed in secondary products like gas and tar. Therefore, pyrolysis[10] offers a way of converting solid biomass found in forestry and agricultural residues into an easily stored and transported liquid, which can be used for the production of heat, power and chemicals.

[10] The future for biomass, pyrolysis and gasification: status, opportunities and policies for Europe Contract No: 4.1030/S/01-009/2001, A V BRIDGWATER, Bio-Energy Research Group, Aston University, Birmingham B4 7ET, UK. November 2002.

Bio-Oil: Biomass may be thermo-chemically converted to liquid bio-oil by using processes called direct liquefaction or fast pyrolysis. The fast or flash pyrolysis processes for creating bio-oil apply rapid heat to small biomass particles at high temperatures in the absence of added oxygen. This process breaks down the biomass structure instantly to produce a high yield of condensable organic liquids. The liquids are typically 65 percent liquid bio-oil, 15 percent solid char and 20 percent gases.

2.7.6.2 Performance

Unprocessed biomass fuel has a relatively low heating value due to its high moisture content. The moisture of biomass fuel can be removed at a temperature above 100° C without experiencing any kind of decomposition, but this changes the heat rate. Drying biomass fuels can reduce transportation and storage costs and make the fuels easier to feed into a furnace. Unprocessed green wood at 50 percent moisture has 4,500 Btu/lb, while after processing, the heating content of dried wood increases to 9,000 Btu/lb. The high water and oxygen content of bio-oils reduces their heating value to less than half the value of petroleum. However, bio-oils are low in viscosity and have been successfully burned in boilers, turbines and diesel engines.

2.7.6.3 Costs

One aspect of biomass operational costs is the price of the feedstock. Costs can be high like short rotation coppice (SRC)[11] or low (negative) like waste residues. Transportation, fuel handling and processing adds to the cost of the feedstock. Practical experience is needed to determine the maintenance costs. The compensation received for the electricity and heat produced can also be decisive in the overall economics of biomass.

Illustrative costs for biomass generation are outlined in Table 2.7.16. Illustrative levelized unit energy costs are presented in Table 2.7.17, with WACCs of 5% and 11%.

Table 2.7.16 — Illustrative Costs: Biomass

	$/MWh	$/kW		
	Variable O&M	Fixed O&M	Capital Cost	Ongoing Capex
Biogas	3.72	59.29	2,207.91	2.30

Source: OPA

[11] Densely planted high-yielding varieties of either willow or poplar, harvested on a two-to-five year cycle.

Table 2.7.17 — Illustrative Levelized Unit Energy Costs: Biomass

LUEC at 5% WACC ($/MWh)	42.4
LUEC at 11% WACC ($/MWh)	61.7

Source: OPA

The above LUECs assume a fuel price of $1/MMBTU, and a capacity factor of 85%. Financial assumptions are the same as those in section 2.7.3.3.

2.7.6.4 Environmental Characteristics:

In the analysis, emission factors were based on gasification of biomass to fuel at a combine cycle gas plant. Water impacts are based on the assumption that the plant uses a pond or tower cooling system.

In the evaluation, it was assumed that wood waste would be the generation fuel. Note that only wood waste, a by-product of the forestry and pulp and paper industry, was analyzed in this study and no analysis was performed on crops grown or harvested specifically as a fuel source, such as switchgrass or peat.

Contaminant and CO_2 Emissions: Contaminant and greenhouse gas emissions are produced during various stages of the biomass life cycle, including during biomass production, transport, and electricity generation. This analysis takes into account CO_2 absorbed during biomass growth.

Land Use: Estimates for land use for biomass generating station were taken from a proposed energy plant project in Saint John, New Brunswick (Goucher, 2005 and CEAA, 2005) and from the proposed NGPP Minnesota Biomass plant in Waseca County Minnesota (EQB, 2003).

Wast: Wood waste fuel generates ash waste (bottom and fly) as a by-product of energy generation. Ash from the generating station would either be used as a soil enhancer or landfilled. There is currently a trial project for utilizing the ash as a substitute for agricultural lime; however, this has not been fully developed. As a result, it was assumed in the present study that biomass ash would be land filled.

Resource Availability: Bioenergy is produced from the conversion of biomass in the form of wood, wood waste from manufacturing activities, agricultural products and residues, or municipal wastes. Production comes mainly from the combustion of waste from forest products and pulp and paper industries generating steam for their own use. Approximately 10 million dry tones of mill residues are used for products or energy annually.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the biomass option.

Table 2.7.18 – Life Cycle Air Impacts – Biomass

	kg / MWh							Sv/GW-year
	Nox	SO2	PM10	PM2.5	HAPs	Contaminant Emissions	CO_2e	Radioactivity
Biomass	0.386	0.105	0.033	0.024		0.8	60	0

Source: SENES and OPA

Table 2.7.19 – Life Cycle Land, Water and Waste Impacts – Biomass

	km^2/MW	L/MWh		T/MWh
	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
Biomass	0.00835	2280	1824	0.000011

Source: SENES and OPA

Table 2.7.20 – Scored Environmental Impacts – Biomass

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
Biomass	2	1	0	1	4	1	1	47.0

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.7 Photovoltaic

2.7.7.1 Overview

Solar technologies for generating electricity are of two general types: photovoltaic (PV), in which sunlight is converted directly into electricity and solar thermal electricity conversion (STEC), in which sunlight is converted first into heat and then into electricity.[12]

Photovoltaic technology uses solid-state semiconductor devices to convert sunlight into direct-current electricity. Although the underlying science was discovered by Becquerel in the nineteenth century, significant progress in commercialization became possible with Bell Labs' invention of the silicon solar cell in 1954 and its early use in powering earth satellites. Silicon is the most commonly used material for PV cells.

[12] Developed in the southern Californian desert during the late 1970s, solar thermal electricity production involves concentrating sunlight to heat a fluid and, in turn, creating steam. The steam is then used to drive a turbine generator.

In a PV system, individual cells are grouped into modules, which can then be grouped to form arrays. Other components common to PV systems include batteries and DC-to-AC inverters. Batteries allow electricity to be stored when the sun shines so that it can be consumed at a later time. Since standard household appliances and electric utilities use AC electricity, an inverter is used to convert the generated DC electricity into AC.

2.7.7.2 Performance

Solar technologies have found a niche in locations beyond the reach of electricity transmission and distribution systems, such as space travel and isolated communities, and in applications such as calculators and certain telecommunications equipment that require very modest amounts of power.

In Ontario, PV systems are mostly used for remote applications[13]. Around the world, the most popular application of PV is on rooftops.[14] For example, the majority of PV systems installed in Japan and Germany are on residential rooftops for sale back into the grid[15]. In Ontario only 5% of PV installation sales are for the grid-connected market, compared to the 78% global figure.[16] The average capacity of a PV system in Ontario is 0.9 kW, compared to the global average rooftop PV capacity of 2-5 kW.[17],[18]
Common efficiencies for PV arrays range from 12 to 15% of the sun's radiant energy[19]. In Ontario, the sun's radiant energy is typically between 3.9 to 4.4 kWh/m2.[20] Other prototypes of PV technologies exist which have higher efficiencies of 25 to 34%, such as single-crystal silicon cells or multifunction gallium arsenide cells.[21]

Solar, similar to wind, is an intermittent resource. Unlike wind, however, the solar resource is coincident with daily peak demand for power.[22] This is illustrated in figure 2.7.1 below, which shows average hourly demand and average hourly radiation in Guelph, Ontario over the period of May 1, 2002 to April 30, 2004. As expected, solar radiation is lowest during the winter and highest during the summer. This is illustrated in figures 2.7.2 and 2.7.3.

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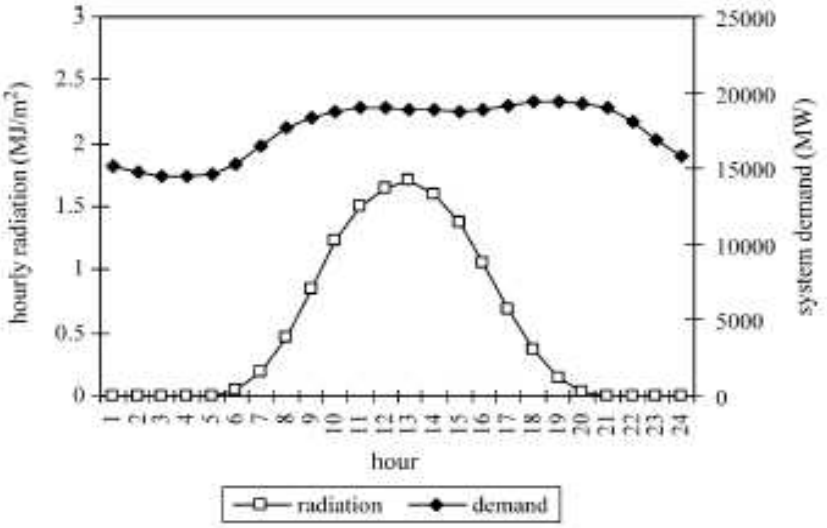
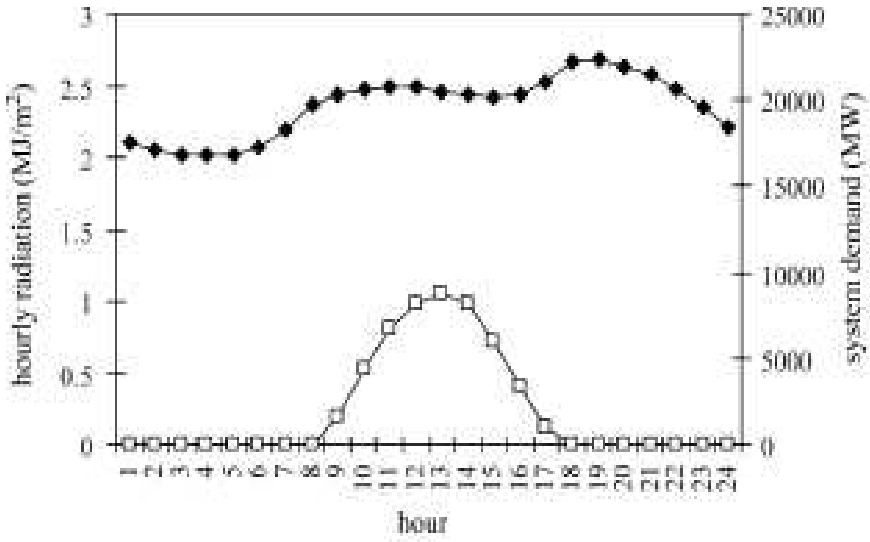
[13] CanSIA. *Solar and Ontario's Future Electricity Supply* (2005). Ontario.
[14] International Solar Energy Society. White Paper (2003). Freiburg, Germany.
[15] Ibid.
[16] CanSIA. *Solar and Ontario's Future Electricity Supply* (2005). Ontario.
[17] Ibid.
[18] REN21Renewable Energy Policy Network. *Renewables 2005 Global Status Report (Draft)* (2005). Washington, DC: Worldwatch Institute.
[19] Pollution Probe. *Primer on the Technologies of Renewable Energy* (2003). Toronto, Ontario
[20] 1) Kosugi et al. *Evaluation of Output and Unit Cost of Power Generation Systems Utilizing Solar Energy Under Various Solar Radiation Conditions Worldwide* (1999). Electrical Engineering in Japan. Vol. 127 (3).
2) CanMET. *PV System Design Manual* (1991). Reproduced in CanSIA. http://www.cansia.ca/solarmap.htm.
[21] U.S. Department of Energy. *Energy Efficiency and Renewable Energy* (2004). Washington, D.C.
[22] Rowlands, I. H. *Solar PV Electricity and Market Characteristics: Two Canadian Case-Studies*. In *Renewable Energy*; Vol.30. No. 6; May, 2005.

Figure 2.7.1 – Average Hourly Ontario Solar Radiation and Demand



Source: Ian H. Rowlands [23] .

Figure 2.7.2.– Average Hourly Ontario Solar Radiation and Demand: January (2003,2004)

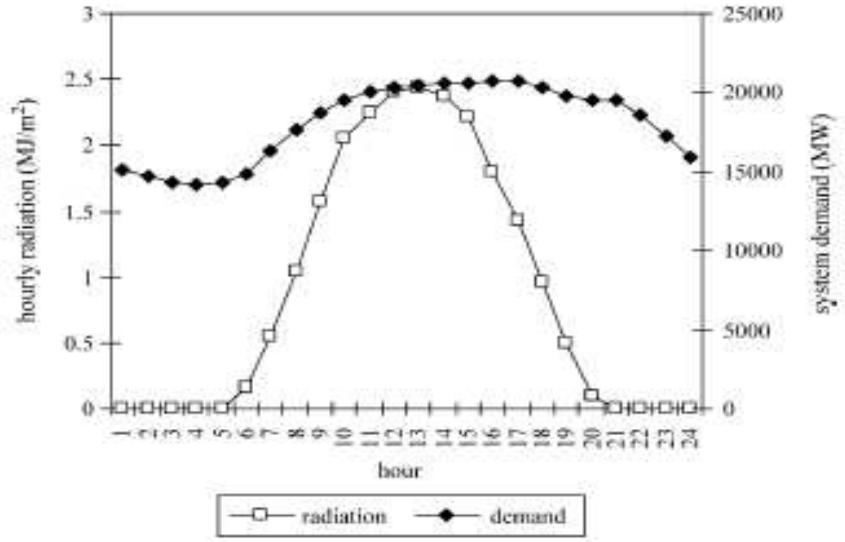


Source: Ian H. Rowlands [24]

[23] Rowlands, I. H. *Solar PV Electricity and Market Characteristics: Two Canadian Case-Studies*. In *Renewable Energy*; Vol.30. No. 6; May, 2005.

[24] Rowlands, I. H. *Solar PV Electricity and Market Characteristics: Two Canadian Case-Studies*. In *Renewable Energy*; Vol.30. No. 6; May, 2005.

Figure. 2.7.3 – Average Hourly Ontario Solar Radiation and Demand: July (2002,2004)



Source: Ian H. Rowlands [25]

2.7.7.3 Costs

Illustrative costs for photovoltaic generation are outlined in Table 2.7.21. Illustrative levelized unit energy costs are presented in Table 2.7.22, with WACCs of 5% and 11%.

Table 2.7.21 – Illustrative Costs: Photovoltaic

	$/MWh	$/kW		
	Variable O&M	Fixed O&M	Capital Cost	Ongoing Capex
Photovoltaic	0.00	12.99	5,613.39	1.15

Source: OPA

Table 2.7.22 – Illustrative Levelized Unit Energy Costs: Photovoltaic

LUEC at 5% WACC ($/MWh)	183.3
LUEC at 11% WACC ($/MWh)	299.4

Source: OPA

The above LUECs assume a capacity factor of 30%. Financial assumptions are the same as those in section 2.7.3.3.

[25] Ibid.

2.7.7.4 Environmental Characteristics

PV is similar to wind in that most of the environmental impacts are generated during the manufacturing and construction phases. As technology rapidly advances, these impacts are being reduced. The environmental impacts associated with manufacturing activities depend on the type of electrical generation used to produce the PV systems. Newer technology tends to be less polluting and, consequently, newer PV systems have a smaller environmental impact.

Similar to wind turbines, there are no contaminant or greenhouse gas emissions associated with the operation of photovoltaic systems.

There are three types of PV installations: (1) Roof Integration; (2) Building Facade Integration; and (3) Open Field Location, otherwise known as Array Field power plants. The present study analyzed only the Array Field option for which the PV land use impact was calculated.

Actual data on land requirements is not readily available since there are few array field power plants presently in operation, as most PV applications are roof integrations. One study[26] identified a PV field array in Italy that was generating 3 MW in about one acre of land. Energy production will, however, depend upon the amount and intensity of sunlight available, which is greater in Italy than Ontario.
The water requirements for PV as a generation option are negligible. As such, for the purposes of this document, water use for PV applications has been set to zero.
Waste production during PV operations would be negligible. As such, for the purposes of this report the value was set to zero.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the photovoltaic option.

Table 2.7.23 – Life Cycle Air Impacts – Photovoltaic

	kg / MWh							Sv/GW-year
	Nox	SO_2	PM_{10}	$PM_{2.5}$	HAPs	Contaminant Emissions	CO_2e	Radioactivity
Photovoltaic	0.10	0.12	0.03	0.02		0.5	127.6	0

Source: SENES and OPA

Table 2.7.24 – Life Cycle Land, Water and Waste Impacts – Photovoltaic

	km^2/MW	L/MWh		T/MWh
	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
Biomass	0.0013	0	0	0

Source: SENES and OPA

[26] NEA, 2001.

Table 2.7.25 – Scored Environmental Impacts – Photovoltaic

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
Biomass	2	1	0	1	0	0	0	41

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.8 Natural Gas

2.7.8.1 Overview

Natural gas plants use either steam turbines or combustion turbines to provide the mechanical power to electrical generators. In steam turbines, it is steam at high temperature and pressure, while in combustion (gas) turbine it is gas expansion, which transfers energy to rotating turbine blades. The turbine is mechanically coupled to a generator, which produces electricity.
If the steam and gas plants are not equipped with the additional equipment such as recuperator or heat recovery steam generator (HRSG), then the useful output of the plants will be power only. Recuperators and HRSGs increase the efficiency of the power plants by using the captured waste heat for either additional electricity generation or an industrial process. The latter is referred to as combined heat and power (CHP) production, or cogeneration.

The word "combined" is common to both CHP and combined cycle. The difference lies in what is being combined. In CHP there is the simultaneous production of electricity and useful heat. In combined cycle, the same thermal energy is used twice to produce electricity: first in a combustion turbine and then in a steam turbine which recovers heat from the exhaust gases of the steam turbine to drive a generator producing electricity. CHP and combined cycle are not mutually exclusive: low-pressure steam from a steam turbine in combined cycle may be used for process heat.

In the present study the following four options utilizing natural gas have been analyzed: Simple Cycle Gas Turbine (SC or SCGT), Combined Cycle Gas and Steam Turbines (CC or CCGT); Combined Heat and Power or Cogeneration, and Fuel Cells.

Simple Cycle Gas Turbine: A simple cycle gas turbine consists of three key components: an air compressor, combustor, and a turbine. In these types of units, hot gases from the combustion of natural gas fuel turn the turbine and generate electricity.

Combined Cycle Gas Turbine: The combined cycle system is a modification of a Simple Cycle system in which the waste heat of the gases leaving the gas turbine is put through a heat exchanger that produces steam that in turn drives a steam turbine-generator, producing additional electricity.

Combined Heat and Power (CHP) or Cogeneration: A CHP or cogeneration system is similar to a CC system in that the first stage is again a Simple Cycle Gas Turbine system. Again, the waste heat of the gases leaving the gas turbine is put through a heat exchanger. The difference is that with CHP system the thermal energy of the steam leaving the heat exchanger is used directly for purposes such as industrial processes or water or space heating, not to generate electricity.

Fuel Cells: A fuel cell consists of two electrodes sandwiched around an electrolyte. Oxygen passes over one electrode and hydrogen over the other, generating electricity, water and heat. Hydrogen fuel is fed into the anode (the negative electrode) of the fuel cell. Oxygen (or air) enters the fuel cell through the cathode (the positive electrode). Facilitated by a catalyst, the hydrogen atom splits into a proton and an electron, which take different paths to the cathode. The proton passes through the electrolyte. The electrons create a separate current that can be utilized before they return to the cathode, to be reunited with the hydrogen and oxygen in a molecule of water.

Three main components of a fuel cell system are the hydrogen fuel reformer, fuel cell stack and the power conditioner.

- A fuel reformer utilizes the hydrogen from natural gas (or other hydrocarbon fuel) that is fed into the fuel cell. The resulting mixture of hydrogen and other gases is then purified. This process lowers the efficiency of the fuel cell. However, because the fuel cell relies on chemistry (converting chemical energy to electrical energy) and not combustion, emissions are smaller than from combustion fuel processes.
- The fuel cell stack converts the hydrogen and oxygen from the air into electricity, water vapor and heat. Furthermore, a single fuel cell produces electricity at only about 0.7 volts. To get this voltage up to a more useful level, many separate fuel cells must be combined to form a fuel-cell stack.
- The power conditioner then converts the DC output from the stack into AC.

2.7.8.2 Performance

Simple Cycle: Simple cycle generation has rapid loading capability, and can reach full power within approximately 10 minutes. Simple cycle plants can respond quickly to sudden changes in demand, and are thus useful for providing peaking service. Simple cycle generators have lower capital costs than combined cycle and CHP generators, but they also have lower efficiencies. Typically, simple cycle generators run for short periods ot time.
Because simple cycle units are primarily used for peaking operation, the most relevant performance measure is the probability the unit will not be available when required (its Derating Adjusted Forced Outage Probability, or DAUFOP). For Canadian plants in 2003 the value was 8.72 percent, and 9.20 percent for the period 1999-2003.

Combined Cycle: Combined cycle generators can start and ramp up to full power within a couple of hours, and can run at a variety of output levels. CC generators can provide both peaking and base load service, but are most useful as intermediate generation. CC generation has a higher capital cost but a lower operating cost than simple cycle generation. As a result, it tends to run more often than simple cycle, but is more efficient when running.

CHP or Cogeneration: Combined heat and power generation is useful as base-load generation. CHP has higher capital costs than SC and CC, but has higher efficiency. The total fuel consumed by a CHP system is less than the total fuel consumed by two separate systems, one producing electricity, and another producing thermal energy. Efficiencies before heat recovery range from 25 per cent to 40 per cent, while overall efficiency after heat recovery could reach 80 to 90 per cent.
One factor that affects cogeneration system economics is system availability and reliability. Electricity is not produced during hours when the cogeneration system is down. Not only must electricity be purchased, but outages can also affect costs of standby service.

Fuel Cells: Large fuel cells are able to generate electricity more efficiently than combustion power plants. The fuel-cell technologies being developed for these power plants generate electricity directly from hydrogen in the fuel cell, but will also use the heat and water produced in the cell to power steam turbines and generate even more electricity.

Fuel cells are ideal for power generation, either connected to the electric grid to provide supplemental power and backup assurance for critical areas, or installed as a grid-independent generator for on-site service in areas that are inaccessible by power lines. Since fuel cells operate silently, they reduce noise pollution as well as air pollution and the waste heat from a fuel cell can be used to provide hot water or space heating for a home.

Modular installation (the installation of several identical units to provide a desired quantity of electricity) provides extremely high reliability of up to 99 percent.

If the fuel cell is powered with pure hydrogen, it has the potential to be up to 80-percent efficient. That is, it converts 80 percent of the energy content of the hydrogen into electrical energy. If another fuel such as methane is used, in which case a reformer is required to convert the methanol to hydrogen, the overall efficiency drops to about 30 to 40 percent.

2.7.8.3 Costs

The capital cost of the gas turbine power plants depends on the size of the plant and the selected technology of turbine systems. The main components of generation costs are the installed cost of the equipment, fuel costs, and non-fuel operation and maintenance (O&M) costs. Fuel cell costs per installed kilowatt are still high relative to those of conventional technology.

The following tables 2.7.26 - 2.7.32 summarize the cost data and levelized costs used in the present study for the natural gas options: simple cycle, combined cycle, CHP or cogeneration, and fuel cells.

Table 2.7.26 – Illustrative Costs: Simple Cycle Gas Turbine

	Variable O&M $/MWh	Fixed O & M $/kW	Capital Cost $/kW	Ongoing Capex $/kW
SCGT	3.42	5.31	635.38	2.30

Source: OPA

Table 2.7.27 – Illustrative Levelized Unit Energy Costs: Simple Cycle Gas Turbine

LUEC at 5% WACC ($/MWh)	109.8
LUEC at 11% WACC ($/MWh)	131.3

Source: OPA

The above LUECs assume a capacity factor of 20% and a gas price at $8/MMBTU.

Table 2.7.28 – Illustrative Costs: Combined Cycle Gas Turbine

	$/MWh	$/kW		
	Variable O&M	Fixed O&M	Capital Cost	Ongoing Capex
CCGT	2.64	16.02	840.65	3.45

Source: OPA

Table 2.7.29 – Illustrative Levelized Unit Energy Costs: Combined Cycle Gas Turbine

LUEC at 5% WACC ($/MWh)	62.6
LUEC at 11% WACC ($/MWh)	70.3

Source: OPA

The above LUECs assume a capacity factor of 85% and a gas price of $8/MMBTU.

Table 2.7.30 – Illustrative Costs: Combined Heat and Power

	$/MWh	$/kW		
	Variable O&M	Fixed O&M	Capital Cost	Ongoing Capex
CHP	2.74	29.88	1294	2.35

Source: OPA

Table 2.7.31 – Illustrative Levelized Unit Energy Costs: Combined Heat & Power

LUEC at 5% WACC ($/MWh)	69.8
LUEC at 11% WACC ($/MWh)	79.4

Source: OPA

The above LUECs assume a capacity factor of 85% and a gas price of $8/MMBTU.

Table 2.7.32 – Illustrative Costs: Fuel Cell (Natural Gas)

	$/MWh	$/kW		
	Variable O&M	**Fixed O&M**	**Capital Cost**	**Ongoing Capex**
Fuel Cell	53.28	6.28	5,340.70	1.15

Source: OPA

Table 2.7.33 – Illustrative Levelized Unit Energy Costs: Fuel Cell (Natural Gas)

LUEC at 5% WACC ($/MWh)	180.8
LUEC at 11% WACC ($/MWh)	221.2

Source: OPA

The above LUECs assume a capacity factor of 85% and a gas price of $8/MMBTU.

2.7.8.4 Environmental Characteristics

Several assumptions were made in the environmental analysis of natural gas options. For the purpose of calculating emissions, single cycle plants were assumed to operate with a thermal efficiency of 40% and combined cycle plants were assumed to operate at an efficiency of 60%. Natural gas was assumed to have a heating value of 1020 Btu/scf. Plants were assumed to operate using dry low-No_x technology (as opposed to steam or water injection systems), which lowers No_x emissions. No life-cycle data was available for fuel cells and hence there was no environmental assessment of this option.

Contaminant and Greenhouse Gas Emission: Contaminant and greenhouse gas emissions are released during upstream natural gas processing and during distribution, construction and power generation phases. Sulphur dioxide can be released during natural gas processing, and carbon dioxide and methane are released during processing and transport.

The emissions associated with construction are a very small fraction of the emissions from the rest of the natural gas cycle – particularly generation.

Radioactivity: Natural gas processing can result in the release of radioactive radon gas.

Land Use and Water Use: Estimates of land use for natural gas fired stations were based on the proposed Sithe Goreway CC plant, the proposed Portlands Energy Centre cogeneration facility, and the proposed Brighton Beach Power plant.

Simple cycle, combined cycle and cogeneration plants use appreciable quantities of water.

Waste: Natural gas and synthetic gas, when burned, do not create waste by-products. As such, operational waste for natural gas was set to zero tonnes per megawatt.

Resource Availability: Canada is the world's third-largest natural gas producer and second-largest gas exporter, and the natural gas industry is very important to the Canadian economy. Canada produces essentially all of the gas used by Canadians, as well as producing large quantities for export to the U.S. Natural gas resources are divided into several categories: established reserves, discovered resources, undiscovered conventional resources, and undiscovered unconventional resources.

Combining these categories, the total remaining resources for Canada are estimated at 630 Tcf or 17.8 trillion m3. Most natural gas production (88%) comes from wells classified as gas wells, with the remaining 12% coming from oil wells. Canadian natural gas production almost doubled between 1988 and 1998, reaching 167 billion m3 in 1998.

Canadian gas demand is projected to increase from 79 billion m3 in 1997 to between 127 and 150 billion m3 by 2020. Total Canadian gas production is forecast to increase from 167 billion m3 in 1997 to between 227 and 255 billion m3 by 2010 At maximum estimated 2010 production, there is an expected 70 years of production remaining.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the natural gas option.

Table 2.7.34 – Life-Cycle Air Impacts – Natural Gas

	NOx	SO_2	PM10	PM2.5	HAPs	Contaminant Emissions	CO_2e	Radioactivity
	kg/MWh	kg/MWh	kg/MWh	kg/MWh	kg/MWh	kg/MWh	kg/MWh	Sv/GW-year
single cycle	0.38024	0.04301	0.02602	0.018	0.00275	1	440	0.03
combined cycle	0.26024	0.02901	0.01702	0.012	0.00183	0.7	290	0.03
fuel cell	Life-cycle data not available							

Source: SENES and OPA

Table 2.7.35 – Life Cycle Land, Water and Waste Impacts – Natural Gas

	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
	km^2/MW	L/MWh	L/MWh	T/MWh
single cycle	0.00018	874	684	0
combined cycle	0.00018	874	684	0
fuel cell	Life-cycle data not available			

Source: SENES and OPA

Table 2.7.36 – Scored Environmental Impacts – Natural Gas

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
single cycle	2	3	0	1	2	0	8	**91**
combined cycle	2	2	0	1	2	0	8	**71**
fuel cell	Life-cycle data not available							

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases , and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.9 Nuclear

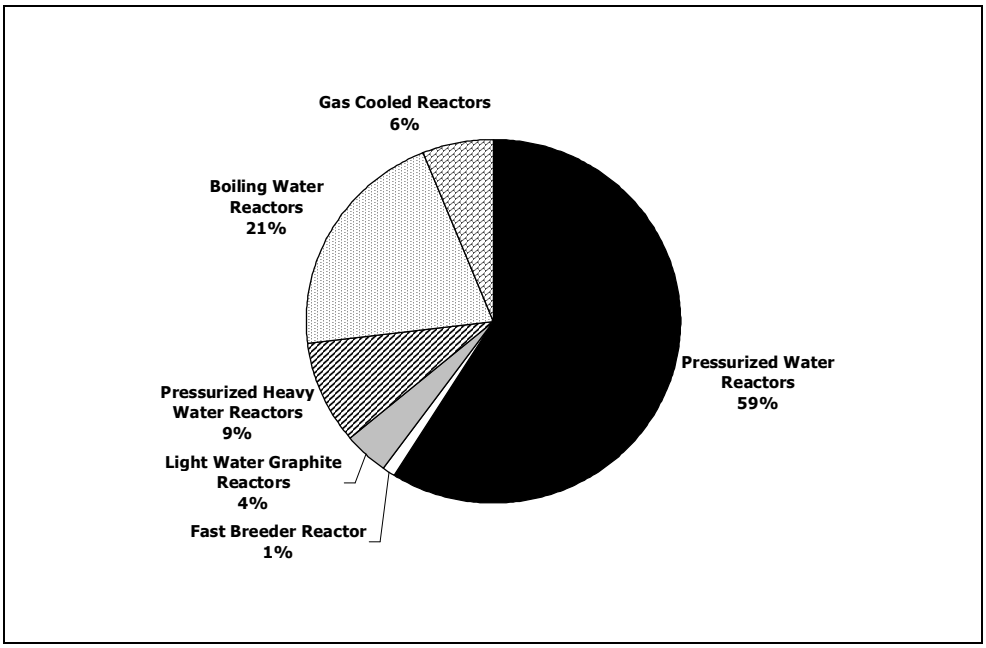
Nuclear reactors produce, contain and control the release of energy from splitting of U_{235} atoms. In electric power plants, the released nuclear energy, much of it in the form of high-speed neutrons, is transformed to heat, producing hot water and ultimately steam. The steam, in turn, drives the turbine-generators to make electricity. The fissioning of uranium is used as a source of heat in a nuclear power station in the same way that the burning of coal, gas or oil is used as a source of heat in a fossil fuel power plant. Nuclear reactors are essentially large steam engines.

Several components are common in most types of nuclear reactors: fuel, the control rods, coolant and the moderator. Control rods regulate the chain reaction of the splitting of atoms. The coolant flows through a heat exchanger, comparable to the radiator fluid in an automobile, carrying away the heat produced by the fission process so that the reactor core does not overheat. The moderator controls the nuclear reaction by slowing down the neutrons released in the fission process – a moderated or slowed-down neutron has a higher probability of subsequently splitting a U_{235} atom, and releasing more nuclear energy, than it would if it had continued to move at a high speed.

There are two main nuclear power types: those moderated by light water and those moderated by heavy water (deuterium oxide). Light water reactors are divided further into Pressurized Water Reactors (PWRs) and Boiling Water Reactors (BWRs), which constitute 59 percent and 21 percent, respectively, of reactor types currently in use around the world. Ontario has 20 CANDU heavy water reactors. CANDU power plants are classified as pressurized heavy water

reactors (PHWRs). Two products from the CANDU line are assessed in this study. One is CANDU 6 reactor. Like its predecessors, it utilizes heavy water as both moderator and coolant. The other is advanced Canada Reactor (ACR-1000). It utilizes heavy water as moderator, but ordinary (light) water as coolant. An expanded discussion on nuclear development in Ontario is found in section 1.2.
Figure 2.7.4 portrays the mix of reactor types in use worldwide.

Figure 2.7.4 – Reactor Types in Use Worldwide, January 2003



Source: World Nuclear Association

2.7.9.1 CANDU Overview and Performance

Overview

The CANDU 6, like its predecessors, uses natural uranium (0.7 percent U_{235}) as fuel. In general terms, this technology has a higher capital cost than light water technology because of the initial cost of heavy water, but a lower fuel cost because no enrichment is required.

Much like its predecessors, the ACR-1000, has retained the following features: horizontal fuel channels, fuel bundle design, low-pressure heavy water moderator, high neutron efficiency and on-power fueling. However, the ACR has also incorporated features from PWR technology, including the adoption of light water as a coolant. The ACR reactor also uses low-enriched uranium (1.5-2.1 percent U_{235}), rather than natural uranium that fuelled its forerunner. The 2.1 percent level of enrichment would be achieved by a combination of natural uranium (0.7 percent U_{235}) and enriched uranium (3 to 4 percent U_{235}).

In the ACR and CANDU 6 designs, several hundred horizontal pressure tubes are submerged

in the heavy water moderator. This horizontal pressure tube design means the reactor can be refuelled on-line. In contrast, a PWR reactor needs to be shut down in order to refuel, and the refuelling outage can last up to two months.

Performance

Generally, the lowest capacity factors for CANDU units belong to those constructed in the 1970s and 1980s, while the highest ones belong to the newer units. Capacity factor is a measure of the productivity of a power production facility. It compares the facility's actual production over a period of time against the theoretical maximum it could have produced if it had operated at continuously full capacity.

The earlier CANDU stations, particularly Picking A and Bruce A have a much lower life time capacity factor. Darlington has a high capacity factor.

As outlined in Table 2.7.37, the average capacity factor for CANDU 6 units in 2004 was 89.1%. The Canadian Nuclear Association (CNA) compares operational performance of nuclear and other technologies.

In Canada, and also the United States, nuclear is base-loaded (i.e. constantly running). This contrasts to the reactors in France, where reactors are taken off-line or operated at reduced power for the appreciable fraction of the time when demand for electricity is well below peak levels. (Nuclear represented 77 percent of France's total electricity generation in 2003).

Table 2.7.37 – CANDU 6 Capacity Factors

			Capacity Factor (%)	
Unit	**Capacity MW**	**In-Service Year**	**2004**	**Lifetime**
Pt. Lepreau (New Brunswick)	680	1983	77.5	82.7
Wolsong 1 (Korea)	679	1983	90.3	86.0
Gentilly 2 (Quebec)	675	1983	87.8	79.3
Embalse (Argentina)	648	1984	86.1	84.8
Cernavoda 1 (Romania)	706	1996	89.7	86.8
Wolsong 2 (Korea)	700	1997	92.6	92.6
Wolsong 3 (Korea)	700	1998	96.4	93.9
Wolsong 4 (Korea)	700	1999	97.4	96.4
Qinshan 4 (China)	700	2002	77.3	84.2
Qinshan 5 (China)	700	2003	94.0	87.8
Simple Average	689		89.1	87.4

Source: Canadian Nuclear Association.

The ACR design, with its light water coolant and low-enriched uranium fuel, is physically smaller and, in AECL's view, more efficient – in terms of capacity and cost – than the CANDU 6. However, because there are no ACRs in commercial operation, there is no track record of

performance data. AECL expects that an ACR, like a PWR of recent design, will achieve a 93 percent capacity factor over its lifetime.

Reason for Darlington Costs Overruns

How the Darlington nuclear station ended up costing $14.3 billion is a subject of much discussion and because confidence in the future performance of CANDU units depends on understanding the reasons, we summarize these major reasons here:

The conceptual estimate for the Darlington station, when it was first released by Ontario Hydro in June 1978, was $5.0 billion. The estimate was based primarily on Bruce A experience, had little detailed engineering to support it, and predicted in-service dates of November 1985 to February 1988. Subsequent to this approval to begin detailed engineering work, the in-service dates were first delayed by 3 to 3.5 years because of reductions in forecast load growth and then accelerated by some 6 to 12 months as part of a government program to create jobs in the construction and electrical equipment industries.

By the time the definitive estimate for the Project was approved by Ontario Hydro in May 1981, the estimated cost had risen by $2.5 billion to 7.5 billion - $2.0 billion due to the net 30 month delay in unit in-service dates and economic forecast changes, and $0.5 billion due to scope and estimate changes.

The units went into service, after several additional delays, over the October 1990 to February 1993 time frame. The total cost for the project was $14.3 billion - $6.9 billion dollars more than the definitive estimate:

Planned schedule changes	$2.5 billion
Unplanned schedule and scope changes	$2.1 billion
Financial policy (accounting) changes	$1.3 billion
Estimate changes (rework, repairs)	$1.0 billion

2.7.9.2 PWR and BWR Overview and Performance

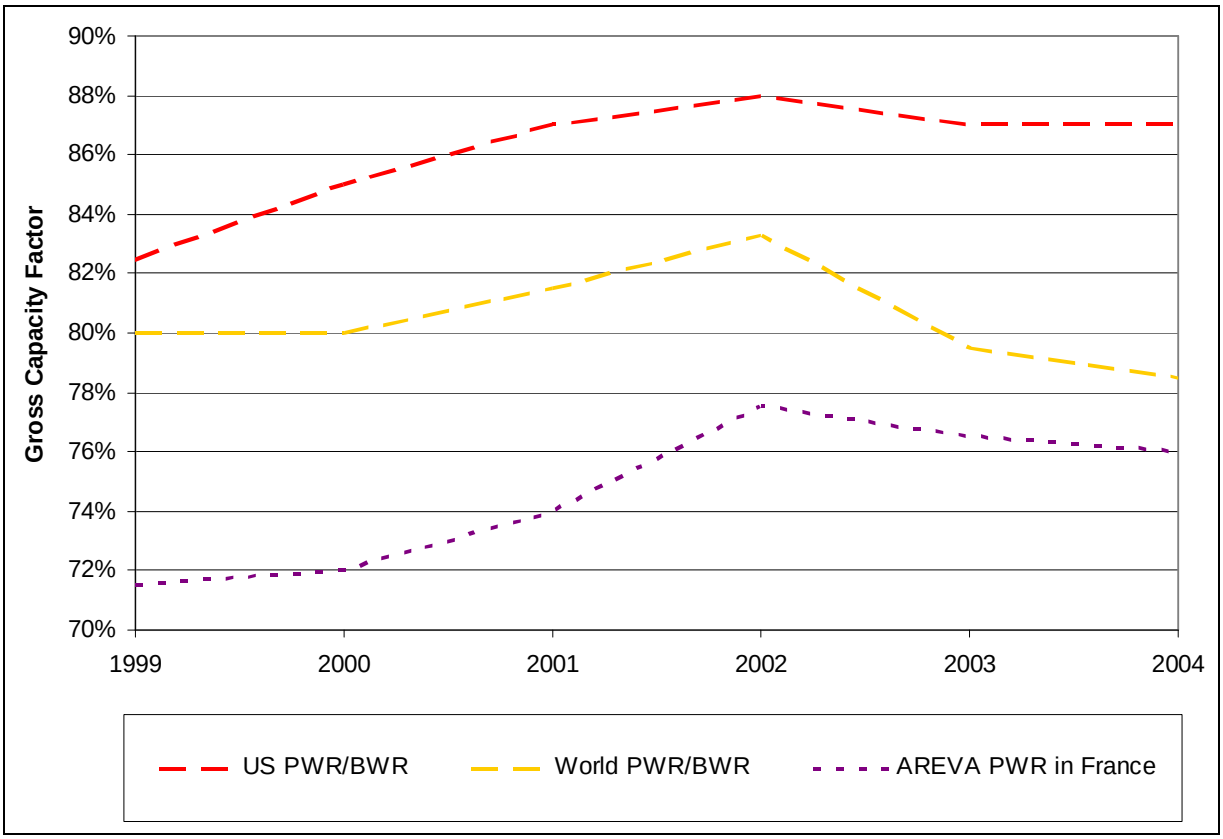
Overview

The PWR is the most common type of nuclear reactor in the world. According the World Nuclear Association, there are 265 PWRs worldwide, with 69 PWRs in use for power generation in the U.S. alone. Virtually all nuclear power reactors in the U.S. are either PWRs or BWRs. The PWR and BWR use enriched uranium (4-5 percent U235), The PWR uses ordinary water as both coolant and moderator. PWR and BWR reactors cannot be refuelled on-line, and require refuelling outages that can last up to two months every 18 to 24 months. PWRs and BWRs are manufactured by General Electric, Westinghouse and Areva.

Performance

The average capacity factor of operating nuclear power plants in the U.S. in 1980 was 56.3 percent; in 1990, 66 percent; and in 2004, 90.5 percent. Performance for BWR and PWR technology are similar.

Figure 2.7.6 – BWR Capacity Factors in Recent Years



Source: COGnizant

2.7.9.3 Costs

Illustrative costs for nuclear generation are outlined in Table 2.7.38. Illustrative levelized unit energy costs are presented in Table 2.7.39, for WACCs of 5% and 11%.

Table 2.7.38 – Illustrative Costs: Nuclear Generation (CANDU 6)

	$/MWh	$/kW		
	Variable O&M	**Fixed O&M**	**Capital Cost***	**Ongoing Capex**
Nuclear	1.42	105.72	2,845	8.85

*$2,600 /kW capital cost plus $245 /kW for heavy water.

Source: OPA

Table 2.7.39 – Illustrative Levelized Unit Energy Costs: Nuclear Generation

LUEC at 5% WACC **($/MWh)**	51.7
LUEC at 11% WACC **($/MWh)**	79.3

Source: OPA

The above LUECs assume a capacity factor of 85%. Financial assumptions are the same as those in section 2.7.3.3. The above costs and LUECs assume a decommissioning cost of approximately $8.3 million per year per twin unit, a fuel cost of $2.4/MWh, spent fuel processing cost of $1.5/MWh, and an ongoing capital expenditure of $10.4 million per year per twin unit.

2.7.9.4 Environmental Characteristics

The environmental evaluation of nuclear generation involves a number of assumptions: Contaminant and greenhouse gas emissions were based on published life cycle data for light water boiling water reactors. The emissions from mining were derived from coal mining emissions but adjusted for the quantity of fuel required per MWh (380 tonnes coal/MWh; 0.029 tonnes uranium/MWh). Radioactivity figures were based on heavy water reactor technology. A once-through cooling system was assumed to determine water impacts. Land use estimates were made on the basis of the three nuclear generating stations in Ontario.

Nuclear Fuel Cycle

The nuclear fuel cycles for all types of reactors have much in common, namely, both the light water and heavy water fuel cycles involve mining, milling, refining, conversion, fuel fabrication, and waste management. All of the nuclear facilities in Canada are licensed and closely monitored by the Canadian Nuclear Safety Commission.

It is recognized that long-term management of spent fuel is a concern to many people. A national program (see Part 3.7) has been established with the mandate to develop an acceptable method of long-term waste management. All current analyses suggest that the doses to people from waste management are likely to be very small.
Light water fuel cycles require a uranium enrichment process. Canada has no enrichment capability and enrichment would be carried out by a facility in the United States, the United Kingdom, France or elsewhere. The above three countries have used fuel reprocessing facilities to recover uranium and plutonium from irradiated fuel to make new fuels.

Mining

Uranium is recovered from the ground through a variety of mining methods - open pit mines, underground mines and in situ leach operations. In Canada, uranium mining is done in accordance with all federal and provincial regulations using both open pit and underground mining methods. Uranium is also mined through open pit and underground methods elsewhere in the world, sometimes in association with other minerals present in the orebody.

In-situ mining involves a uranium ore deposit, often in a sandstone type of material, that is amenable to the extraction of uranium by injecting leaching solutions into the ground and then recovering this solution from a ring of wells surrounding the injection well. Uranium is then extracted from the uranium-rich leach solution.

Milling

Uranium ore from open pit or underground mining is sent to a uranium mill for uranium recovery. In the mill, the ore is ground and then subjected to an aggressive chemical leaching process, followed by uranium recovery. The product of milling is a uranium concentrate usually referred to as yellowcake. The sand-like tailings that are left over from the uranium recovery process are sent to a tailings management area for long-term care.[27].

Refining and Conversion

All uranium concentrate from Canadian mines is shipped by truck to Blind River for further purification in a process referred to as refining. After refining in Blind River, the purified uranium (now in the form of UO_3) is transported to Port Hope, Ontario in specially designed containers. At the Port Hope Conversion facility, part of the UO_3 is converted to UO_2 to produce fuel for CANDU reactors and the rest is converted to uranium hexafluoride (UF_6) and then transported to the United States or overseas to an enrichment plant.

Fuel Fabrication

Once refining and conversion is completed, UO_2 powder is then transported to fuel fabrication plants (Zircatec in Port Hope or General Electric plants in Toronto and Peterborough (Ontario)).

[27] The Key Lake mill in Saskatchewan, which currently produces uranium concentrate from McArthur River ore, will also in the future produce uranium concentrate from part of the production from the Cigar Lake mine. Ammonium sulphate, a by-product of the milling process, is sold commercially as fertilizer. About 235,000 tonnes per year of new tailings are added to the tailings basin each year. At Key Lake, the tailings are managed under a water cover in a below ground pit, which minimizes the footprint of the tailings and the release of radon gas. Overall, the Key Lake mill sits on 3,476 hectares, of which 762 hectares is considered to be disturbed.

Radioactivity

In evaluating nuclear technologies, it is important to understand that all of the western countries with commercial nuclear power are subject to meeting or bettering an annual radiation dose of 1 mSv/a[28] (1000 μSv/a) to the most exposed individual. In practice, the actual doses from nuclear generation are very much lower.

For example, in 2004, the doses to the most exposed person living next to the Pickering and Darlington nuclear generating stations were 4.1 μSv (0.0041 mSv) and 1.2 μSv (0.0012 mSv) respectively. Typical levels are 10 μSv/a for BWRs and HWRs and 2 μSv/a for LWRs. Doses decrease as the square of the distance from a nuclear facility.

For context, the estimated world-wide per caput dose from natural background sources of radiation and radioactivity is 2.4 mSv per year (2,400 μSv per year) which can be compared to above estimates of 4.1 and 1.2 μSv for the most exposed persons living next to the Pickering and Darlington nuclear generating stations.

Future doses from nuclear generation to the most exposed nearby resident arising from operation of any of the alternative nuclear reactors, are unlikely to be more than about 10 μSv/a. Thus, the maximum individual dose is not informative with respect to alternative nuclear generation technologies. Therefore, the concept of collective dose has been adapted for present purposes. In addition to doses in current years, there will be future doses for long-lived radionuclides. This includes the collective dose from radon from mill tailings out to 10,000 years in the future

Waste

Wastes generated during routine operation were estimated on the basis of those at the Pickering and Bruce plants and include:

- Low-level radioactive waste in the form of clothing, mop heads, rags, paper towels and floor sweepings
- Intermediate level waste such as used reactor components, or resins and filters to keep the reactor water systems clean
- Used fuel bundles
- Hazardous Wastes - liquid and solid and
- Combustion by-products (ash and gypsum)

[28] 1 mSv/a is one milli Sievert per annum (year), a measure of radiation dosage.

To provide consistency with reported numbers for thermal generation, only the stored nuclear waste is reported. Exposure to radioactivity arising from waste management is captured in the radioactivity component of the air impacts category.

Resource Availability: Uranium is a common element in the earth's crust. Small masses of fissile uranium can release enormous amounts of energy by means of nuclear fission. Complete fission of uranium (isotope U_{235}) can produce 2.5 million times more heat than the combustion of an equal weight of carbon in wood, coal or natural gas. Uranium is used mainly to fuel nuclear reactors, where energy released from a controlled fission reaction is used to generate electricity.

Canada is the world's leading producer of uranium. In 1997, Canadian uranium production amounted to more than 12,000 tonnes of uranium, approximately 1/3 of total global production. Canada has significant uranium resources of current economic interest. As of January 1, 1998 total recoverable uranium resources in Canada were estimated at 419,000 tonnes of uranium. At 1998 rates, this was equal to about 40 years of production. However, there is significant potential for discovering more uranium resources in Canada.

Other estimates of years of remaining production for uranium were made from world uranium reserves and consumption, with estimates ranging from 172 years to 250 years.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the nuclear option.

Table 2.7.40 – Life Cycle Air Impacts – Nuclear

	kg / MWh							Sv/GW-year
	NOx	**SO_2**	**PM_{10}**	**$PM_{2.5}$**	**HAPs**	**Contaminant Emissions**	**CO_2e**	**Radioactivity**
Nuclear	0.188	0.01	0.013	0.009		0.3	12	10.7

Source: SENES and OPA

Table 2.7.41 – Life Cycle Land, Water and Waste Impacts – Nuclear

	km^2/MW	L/MWh		T/MWh
	Land Use	**Water Use – Withdrawal**	**Water Use – Consumption**	**Waste**
Nuclear	0.001465	228000	1520	0.000075

Source: SENES and OPA

Table 2.7.42 – Scored Environmental Impacts – Nuclear

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
Nuclear	1	1	6	1	4.5	1	5.3	47.8

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases , and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.10 Coal

2.7.10.1 Overview

Coal combustion technologies can be categorized into pulverized coal combustion with sub-critical or supercritical steam cycle; and advanced clean coal technologies such as fluidized-bed combustor (FBC), pressurized fluidized-bed combustors (PFBC), and atmospheric fluidized-bed combustors (AFBC).

Pulverized coal combustion (PCC) is the most commonly used method in coal-fired power plants. The pulverized coal power plant design is based on the use of pulverized coal feeding a conventional steam boiler and steam turbine.
The coal is prepared by grinding it (typically, 70 percent of the coal is ground to pass through a mesh screen) to a very fine consistency for combustion. Pulverized coal is blown with part of the combustion air into the plant through a series of burner nozzles. Combustion then takes place at temperature from 1,300 to 1,700 C.

Ash is formed in the combustion chamber while coal combusts. The primary advantage of PCC combustion is the very fine nature of the fly ash[29] produced. In general, PCC combustion results in approximately 65 – 85 percent fly ash, and the remainder is coarser bottom ash[30] or boiler slag[31]. Various technologies or components have been developed in order to reduce the environmental impacts of using coal for power production in new plants. The principal developments involve increasing plant thermal efficiencies by raising the steam pressure and temperature, and ensuring that flue gas cleaning units meet emissions limits and environmental requirements. Since both the highest and lowest temperatures of the working fluid govern the efficiency of the plants, strict temperature and pressure limits are indicative of more advanced technology.

29 Fly ash is the coal ash that exits a combustion chamber in the flue gas and is captured by air pollution control equipments such as electrostatic precipitators, baghouses , and wet scrubbers.
30 Bottom ash consists of agglomerated ash particles formed in pulverized coal boilers that are too large to be carried in the flue gases and impinge on the boiler walls or fall through open grates to an ash hopper at the bottom of the boiler. Bottom ash is typically gray to black in color, is quite angular, and has a porous surface structure.
31 Boiler slag is a molten ash collected at the base of slag tap and cyclone boilers that is quenched with water and shatters into black, angular particles having a smooth glassy appearance.

Most of the PCC plants use sub-critical steam cycles with pressures less than 22 megapascals (MPa) while supercritical steam cycles utilize steam at a pressure of 24 MPa, and temperature ranges of 540 to 560 C. The higher steam pressure in supercritical plants results in higher energy efficiency.

2.7.10.2 Performance

PCC boilers have been built to match steam turbines that have outputs between 50 and 1,300 MW. In order to take advantage of the economies of scale, most new units are rated at over 300 MW, but there are relatively few really large ones with outputs from a single boiler/turbine combination of over 700 MW.

The overall thermal efficiency of some older, smaller units burning poor quality coals in some cases can be less than 30 percent. Most of the PCC plants with sub-critical steam cycles are very reliable, but their efficiency is in the region of 34 to 36 percent.

New plants with super-critical steam, however, can now achieve overall thermal efficiencies in the range of 43 to 45% and they are already commercially viable.[32] Increasing the steam pressure and temperature from 25 Mpa and 540 C to 30 Mpa and 600 C can increase the thermal sparring efficiency by nearly 2 percentage points. New high-temperature alloys are under development with the aim of facilitating steam temperatures as high as 700 C. This could achieve net efficiencies of 50 percent with PCC. The necessary emission control measures can be taken with a relatively small effect on overall thermal efficiency.

No new coal-fired facilities were not considered in this study. However, the gasification option was considered and is described in Section 2.7.11.

2.7.10.3 Costs

Illustrative costs for a coal generator are outlined in Table 2.7.43.

32 IEA Clean Coal Center, http://www.iea-coal.org.uk/templates/ieaccc/content.asp?PageId=65.

Table 2.7.43 – Illustrative Costs – Coal Generation

	$/MWh	$/kW		
	Variable O&M	**Fixed O&M**	**Capital Cost**	**Ongoing Capex**
Coal	7.04	11.50	1,840.00	3.45

Source: OPA

2.7.10.4 Environmental characteristics

Several assumptions were made in this analysis regarding the environmental impacts of coal-fired generation. It was assumed that the generating plant would use pulverized coal and would operate at 35% thermal efficiency with NO_x, SO_2 and particulate mitigation controls installed. Low NO_x burners plus post burner control were assumed to reduce NO_x emissions by 86%, scrubbers were assumed to remove 90% of SO_2 emissions; and electrostatic precipitators and fabric filters were assumed to remove 99% of particulate matter. Water impacts were determined on the basis that a once-through cooling system would be used. The evaluation of coal as a thermal generation fuel assumed that the coal used as fuel would be bituminous and sub-bituminous coal.

Contaminant and Greenhouse Gas Emissions: Contaminant emissions, including NO_x, SO_2 and particulate matter, are released during coal mining, transport and combustion. In addition, greenhouse gases are also released during these phases, including methane, carbon dioxide, and nitrous oxide. Coal has the highest carbon content of any of the fossil fuels per unit of primary energy content. Combustion of coal also results in the release of mercury, benzene, and formaldehyde.

Radioactivity: The major component of coal is carbon. However, depending on its source, coal contains varying amounts of inorganic matter including trace elements and radionuclides. During mining operations, radon is released along with the methane that is trapped in the coal matrix.

During coal combustion, most of these elements are released and distributed between the gas phase and solid combustion products depending on the volatility of each element. Most of the radon gas is lost in stack emissions because it is transferred to the gas phase. The decay of less volatile elements such as uranium and thorium results in air emissions of radioactivity. Some of the radioactivity will also distribute to the bottom ash.

The result, which may be surprising to some, is that in the U.S. the population radioactivity dose from coal plant operation is about 100 times that from nuclear plant operation.

Land Use: There are land use impacts associated with the site of the plant and influenced in part by the fact that it may include a "buffer zone" between the station and nearby communities.

Waste: Burning coal for electricity production produces fly ash and gypsum as waste. In Ontario in 2004, 91% of fly ash and gypsum created by coal-fired electricity generation was diverted from landfills through recycling. The fly ash is sold for use in binding materials, while recycled gypsum is used in manufacturing drywall. Of the total waste in 2004 of 950,045 tonnes, 84,421 tonnes had to be landfilled.

Resource Availability: Canada is richly endowed with coal and holds about 1% of the world's coal resources. Thermal coal (steam coal) is used primarily to generate electricity. Coal currently plays a large role in Canada's energy sector, with 90% of domestic coal consumption used in electricity generation. Canada's coal resources are widely distributed. Recoverable coal reserves, approximately 6.5 billion tonnes, represent only a small portion of Canada's total coal resources. Coal exports are projected to increase from 34 million tonnes in 1995 to 37 million tonnes in 2020. Domestic coal demand is expected to increase from 53 million tonnes in 1995 to 74 million tonnes in 2020.

Roughly 100 years remain for coal production from established reserves. If all coal resources of immediate interest are considered, at least 1,000 years of production remain.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the coal option.

Table 2.7.44 – Life-Cycle Air Impacts – Coal

	kg / MWh							Sv/GW-year
	Nox	SO2	PM10	PM2.5	HAPs	Contaminant Emissions	CO_2e	Radioactivity
Coal	0.408	0.711	0.071	0.025	0.000307	2.1	1,020	20

Source: SENES and OPA

Table 2.7.45 – Life-Cycle Land, Water and Waste Impacts – Coal

	km^2/MW	L/MWh		T/MWh
	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
Coal	0.0057	2280	1824	0.0032

Source: SENES and OPA

Table 2.7.46 - Scored Environmental Impacts – Coal

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
Coal	5	7	10	1	3.5	10	2	216.5

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gas, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.11 Gasification

2.7.11.1 Overview

Gasification is an emerging coal generation option that has the advantage of using the low cost of coal relative to that of natural gas, while reducing the environmental impacts associated with coal. The gasification system consists of four main stages: feeding, gasification, gas cleaning and utilization of combustible gas for steam and electricity generation.

Coal, (typically in the form of a slurry) is fed along with an amount of oxygen that is insufficient for complete combustion. The result is that the reagent mixture is only partly combusted into syngas, a mixture of carbon monoxide (CO) and hydrogen (H^2). The syngas mixture contains the original impurities, sulphur compounds and particulates, which are then removed in the gas cleaning stage. The clean syngas is then combusted, the CO and H_2 being converted to CO_2 and H_2O (water/steam), with the release of energy in the form of heat that drives a turbine-generator, producing electricity and excess heat. This excess heat is in turn used to generate steam, which drives a second turbine-generator, generating additional electricity. The process is termed "combined cycle" because electricity is produced in two generation stages.

2.7.11.2 Performance

A number of gasification plants around 250 MW in size are operating in Europe and the US. The reliability, capital costs and environmental results of modern gasification technologies have been documented; however, the technology is typically judged to be emerging rather fully commercially proven. Puget Sound Electric, for example, in its 2005 IRP, anticipates the technology is not suitable for commitment at the present time, but is confident it will evolve to become commercially viable for a 2015 in-service date. The OPA reaches similar conclusions – this question is discussed more fully in Part 3.8. Gasification units are complex chemical plants and economies are realized by building the units in a central location and transporting them to the plant sites. Weight and size limitations on transport may limit their output to about 300 MW.

Depending on the configuration and the level of integration of the various processes, the current gasification plant designs are capable of achieving 40 to 42 percent efficiency with heat rates in the 8,400 to 8,600 MMBTU/kWh range. Currently, the gas cleaning stages for particulates and sulphur removal can only be carried out at relatively low temperature, which restricts the overall efficiency. Higher efficiencies (45 percent) are possible when a high gas inlet temperature to the gas turbine can be achieved. Future efficiency gains from advanced turbine designs and a more efficient production of oxygen are expected to widen the advantage gap between gasification and competing coal technologies such as circulating fluidized bed (CFB) and supercritical boilers.

Gasification by-products consist of more than 99 percent pure elemental sulphur, and unlike

pulverized coal plants, no fly ash is generated. With gasification technology more than 99 percent of the SO^2 is removable and the level of NOx emissions is below 100 ppm.

Highly integrated plants such as gasification tend to have long operating start-up times (compared to PCC plants), and hence may only be suitable for base-load generation.

2.7.11.3 Costs

Illustrative costs for are outlined in Table 2.7.47. Illustrative levelized unit energy costs are presented in Table 2.7.48, for WACCs of 5% and 11%.

Table 2.7.47 – Illustrative Costs: Gasification

	$/MWh	$/kW		
	Variable O&M	Fixed O&M	Capital Cost	Ongoing Capex
Gasification (without carbon sequestration)	1.13	67.86	1,922.65	3.45
Gasification (with carbon sequestration)	5.96	67.86	2,499.45	3.45

Source: OPA

Table 2.7.48 – Illustrative Levelized Unit Energy Costs: Gasification

LUEC at 5% of WACC ($/MWh)	68.3
LUEC at 11% of WACC ($/MWh)	90.9

Source: OPA

The above LUECs assume a capacity factor of 85% and a coal price of $2.5/MMBTU.

2.7.11.4 Environmental Characteristics

Environmental impacts for gasification were developed on the basis that coal would be the fuel gasified. Values are reported for operations both with and without CO_2 sequestration. However, it was assumed that 90% of CO_2 resulting from operations would be sequestrated. Land use for a gasification plant is similar to that of a coal plant, and water use is similar to that of a natural gas plant.

Contaminant and Greenhouse Gas Emissions: As is the case for conventional coal, the mining and transport of coal for gasification in a gasification plant will result in the release of contaminant and greenhouse gas emissions.

Contaminant emissions released during other stages of the life-cycle were based on those reported by the U.S. Department of Energy for the gasification plant at Wabash River.[33]

Life cycle emissions of greenhouse gases were based on Corti and Lombardi; (2003) and Dorland et al (1997). [34]

Radioactivity: Similar to conventional coal, mining of coal for use in a gasification plant results in exposure to radioactivity.
Waste: Waste production in a gasification plant consists of a solid slag that is formed from the molten ash flowing from the bottom of the gasifier. This slag by-product of gasification is subsequently sold for use as aggregate in construction or as grit for roofing and abrasives. Reported slag produced at the 315 MW (gross) Tampa Electric gasification project was 1,248 tonnes/year, all of which is recycled and therefore diverted from landfill.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the gasification option.

Table 2.7.49 – Life-Cycle Air Impacts – Gasification

	NOx	SO2	PM10	PM2.5	HAPs	Contaminant Emissions	CO_2e	Radioactivity
	kg/MWh	kg/MWh	kg/MWh	kg/MWh	kg/MWh	kg/MWh	kg/MWh	Sv/GW-year
without CO_2 removal	0.5	0.62	0.02	0.01	-	1.8	910	20
with 90% CO_2 removal	0.5	0.62	0.02	0.01	-	1.8	240	20

Source: SENES and OPA

Table 2.7.50 – Life Cycle Land, Water and Waste Impacts – Gasification

	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
	km^2/MW	L/MWh	L/MWh	T/MWh
without CO_2 removal	0.0057	874	684	0
with 90% CO_2 removal	0.0057	874	684	0

Source: SENES and OPA

[33] U.S. Department of Energy and Wabash River coal Gasification Project Joint Venture. "Clean Coal Technology – The Wabash River Coal Gasification Repowering Project".
[34] Corti A. and L. Lombardi, "Biomass Integrated Gasification Combined cycle with Reduced CO_2 Emissions: Performance Analysis and Life cycle Assessment (LCA)." Energy 29 (2004) 2109-2124. Dorland, C., H.M.A. Jansen, R.S.J. Tol and D. Dodd, ExterneE National Implementation – The Netherlands. Final Report, November 1977.

Table 2.7.51 – Scored Environmental Impacts

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
without CO_2 removal	4	6	10	1	2	0	2	**175**
with 90% CO_2 removal	4	2	10	1	2	0	2	**95**

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases, and 1 to all other categories. For further information, please see Part 2.6

Source: SENES and OPA

2.7.12 Oil

2.7.12.1 Overview

Oil is used for the generation of a small and declining portion of the world's electricity. Its use for electricity generation has been declining since the 1970s. The viability of oil-fired electricity generation is linked to the price of crude oil, the rise of which has made oil fired electricity generation relatively less economic. A number of oil-fired generating units have been converted to operate on another fuel source (such as natural gas), allowing some degree of hedging against fuel price volatility or fuel availability. Ontario's Lennox facility has the capability to use oil or natural gas as a fuel. Oil-fired generators are also used to a limited extent in Ontario as back-up on-site generators.

2.7.12.2 Performance

According to EIA (2005), oil consumption in the electric power sector uses three main types of oil derivatives, including distillate fuel oil, residual fuel oil and petroleum coke. Petroleum coke and residual oil include some of the final products of the condensation process in cracking crude oil. Residual oil may include waste oils as well. Residual oils and petroleum coke are generally very viscous and may require preheating prior to burning in a generating unit. Distillate oils are typically virgin oils formed by the cracking of a crude oil product. Generally, large-scale oil-fired generators burn the fossil fuel in a burner which heats water to steam in an adjacent vessel. The steam that is produced then drives a turbine which rotates an electrical generator.

Most large oil-fired were built during periods of less expensive crude oil. They are generally simple units consisting of a burner and a boiler in which steam is produced that drives a generation turbine. Their conversion efficiencies are similar to, or even lower than, coal-fired generating stations. Outside of Ontario, there are a few large oil-fired generators remaining in the eastern provinces. Some of the units are dual-fuelled.

No new oil-fired generation resources were considered in this study.

2.7.12.3 Capital and operating costs

Illustrative costs for oil-fired generation are outlined in Table 2.7.52

Table 2.7.52 – Illustrative Costs: Oil Generation

	$/MWh	$/kW		
	Variable O&M	Fixed O&M	Capital Cost	Ongoing Capex
Oil	6.32	27.06	650.59	2.35

Source: OPA

2.7.12.4 Environmental Characteristics

In evaluating the environmental impacts of oil-fired generation, it was assumed that dry low-NO_x technology, flue gas desulpherization and particulate controls would be used. For the purpose of calculating emissions, it was assumed that 22% of the crude oil would be extracted from tar sands, with the remainder extracted conventionally.

Contaminant and Greenhouse Gas Emissions: Contaminant and greenhouse gas emissions are released during conventional oil extraction and tar sands extraction. In general, extraction from tar sands results in much higher emissions. Contaminant and greenhouse gas emissions are also released during transport, refining, construction and fuel oil combustion.

Radioactivity: Radioactive radon can be released from the combustion of fuel oil.

Waste: While burning oil to generate electricity does not produce a waste product, this is because the oil has already been refined to a fuel oil that burns with little by-product. However, waste is generated in the refining process and this waste is separate from that produced during extraction. Waste output includes oily waste, catalyst, industrial waste and domestic waste.

Resource Availability: Canada's proven oil reserves have recently (late 2004) been modified to include private sector estimates of oil sands reserves, raising oil reserve estimates from a mere 4.9 billion barrels to nearly 180 billion barrels. The inclusion of oil sands reserves in the estimate is slightly controversial because these potential sources are much more difficult, and therefore more expensive, to extract and process than conventional oil reserves.

Nevertheless, the new estimates place Canada second only to Saudi Arabia in available oil reserves. Production of oil in Canada in 2004 reached 3.1 million barrels per day while consumption was estimated at 2.3 million barrels per day.[35] Using these 2004 estimates of production and reserves, and assuming no increase in production without corresponding

[35] See Part 4.4, p. 7-50.

increase in available reserve, there remains 158 years of oil production in Canada.

Quantified Environmental Impacts: The following tables summarize the environmental impacts of the oil option.

Table 2.7.53 – Life Cycle Air Impacts – Oil

	kg / MWh							Sv/GW-year
	Nox	SO2	PM10	PM2.5	HAPs	Contaminant Emissions	CO_2e	Radioactivity
Oil	0.713	0.777	0.0278	0.0189	0.0008529	2.2	1520	0.5

Source: SENES and OPA

Table 2.7.54 – Life Cycle Land, Water and Waste Impacts – Oil

	km^2/MW	L/MWh		T/MWh
	Land Use	Water Use – Withdrawal	Water Use – Consumption	Waste
Oil	0.0013	2973	1962.6	0.00099

Source: SENES and OPA

Table 2.7.55 – Scored Environmental Impacts

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	Total Impact (Weighted)
Oil	5	10	1	1	5	3	5	**265**

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gas, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

2.7.13 Distributed Generation

Ontario is seeing growing interest in Distributed Generation (DG). Despite its long history (dating back to the dawn of the electrical era), DG currently plays a limited role in meeting Ontario's electricity requirements. Further work is required to facilitate a greater role for DG in this regard. Experience with DG in other jurisdictions highlights a number of areas for potential focus.

2.7.13.1 Definitions

Broadly speaking, DG refers to small-scale power generation or storage (typically ranging from under a kW to tens of MW) which is located close to where electricity is consumed. The Institute of Electrical and Electronics Engineers Inc. (IEEE) defines DG as ''The generation of electricity

by facilities sufficiently smaller than central generating plants as to allow interconnection at nearly any point in a power system".[36]

EPRI defines DG more comprehensively as "the integrated or standalone use of small, modular, electricity generation or energy storage resources by utilities, utility customers, and/or third parties in applications that benefit the electric system, specific end-use customers or both"[37]. EPRI specifies DG as usually less than 60 MW, used on-site or nearby, and can include cogeneration, cooling, back-up generation and on-site facilities. Ackerman et al define DG as an electric power source connected directly to the distribution network or on the customer side of the meter.[38]

2.7.13.2 Technologies and Applications

DG comes in a variety of technologies and applications. Technologies include reciprocating engines, gas turbines, micro turbines, fuel cells, photovoltaics, wind, other renewables, and power storage systems. Applications include emergency and standby service, off-grid, peak reduction, and combined heat and power. In the U.S., it is estimated that 81% of DG capacity "comprises small-to-medium reciprocating engines serving end-user needs for emergency/standby applications"[39]. Further, only about 13% of US total DG capacity is interconnected with the electrical transmission and distribution system[40].

2.7.13.3 Benefits of Distributed Generation

Because DG installations require relatively short construction times and can be added in small increments, they offer flexibility for adapting to changing requirements. Lovins *et al*. note that DG can, among other things, help reduce forecasting and financial risk[41]. In particular, Lovins *et al* posit that on account of its quicker lead-times, DG can help reduce the risk of over- or under-building resources to meet future expectations, as well as to mitigate the magnitude of the financial consequences where an over- or under-build actually occurs.

Other benefits of DG include that it is amenable to combined heat and power applications, can use local fuel sources, can offer localized voltage and reactive power support, can help reduce

[36] Charles, Richard & Barry Johnson. *Wide-Scale DG Deployment. Reality or Myth?* In Cogeneration and On-Site Power Production. Volume 2, Issue 3; May – June 2001

[37] EPRI. *Distributed Energy Resources: Current Landscape and a Roadmap for the Future*, Palo Alto, CA, 1008415. (2004)

[38] Ackerman, T., G. Anderson and L. Soder (Ackerman *et al*.), (2001), *Distributed Generation: a Definition*. Electric Power Systems Research, 57, pp. 195-204.

[39] Rastler, Dan. *Are Distributed Energy Resources Gaining Traction?* In Public Utilities Fortnightly; February 2005; Volume 142, No. 2

[40] Ibid.

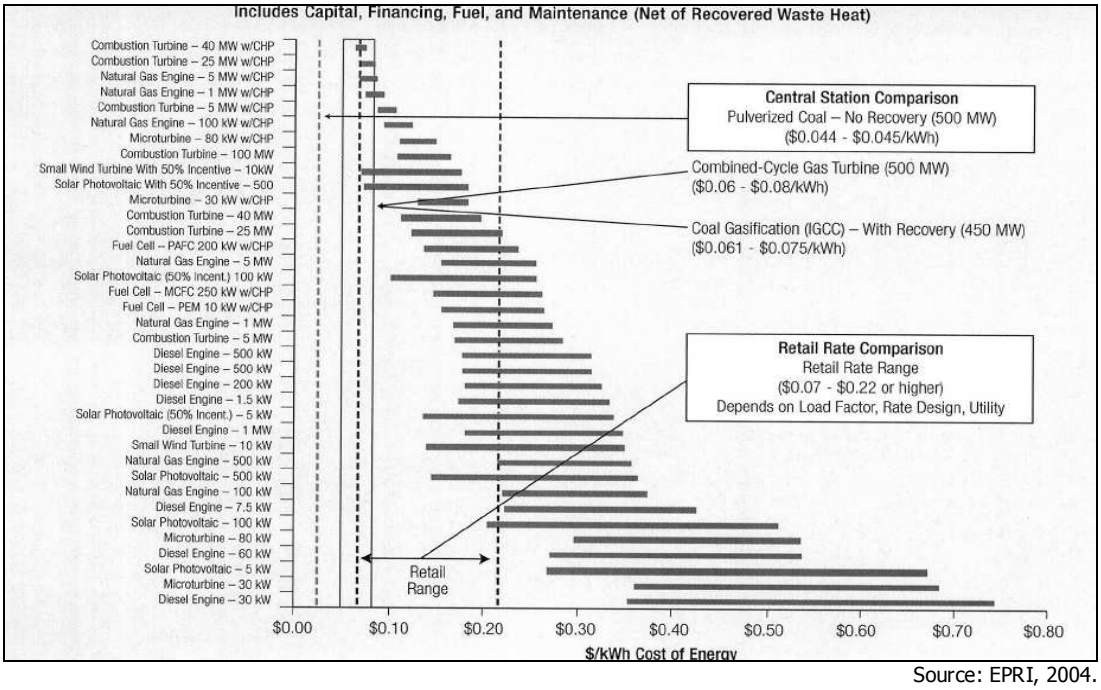
[41] Lovins, A.B., E.K. Datta, T. Feiler, K.R. Rabago, J.N. Swisher, A. Lehmann and K. Wicker (Lovins *et al*). Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size. Rocky Mountain Institute, 2002.

transmission and distribution losses, and can enhance diversity of power generation resources and sites. Moreover, DG developments can provide opportunities for community participation in energy and resource management.

2.7.13.4 Costs

The costs of DG are relatively high at present, but vary by site and equipment. Rastler notes "the costs to design, purchase, and install [DG] remain critical – and often prohibitive – factors in the overall economics of distributed power options", and argues that they "need to be significantly reduced for larger market impacts to occur".[42] However, he goes on to observe that "while the costs of [DG] do not compare with the all-in cost of 500 MW combined cycle gas turbine, some [DG] can be cost-effective in comparison to the delivered cost–of-energy to end-users (retail rates) depending on the rate structure and level, as well as customer load factor."[43] Figure 2.7.7 illustrates the total energy costs of various DG technologies (in $U.S.).

Figure 2.7.7 – Range of Total Energy Cost for Distributed Generation


Includes Capital, Financing, Fuel, and Maintenance (Net of Recovered Waste Heat)
Combustion Turbine – 40 MW w/CHP
Combustion Turbine – 25 MW w/CHP
Natural Gas Engine – 5 MW w/CHP
Natural Gas Engine – 1 MW w/CHP
Combustion Turbine – 5 MW w/CHP
Natural Gas Engine – 100 kW w/CHP
Microturbine – 80 kW w/CHP
Combustion Turbine – 100 MW
Small Wind Turbine With 50% Incentive – 10kW
Solar Photovoltaic With 50% Incentive – 500
Microturbine – 30 kW w/CHP
Combustion Turbine – 40 MW
Combustion Turbine – 25 MW
Fuel Cell – PAFC 200 kW w/CHP
Natural Gas Engine – 5 MW
Solar Photovoltaic (50% Incent.) 100 kW
Fuel Cell – MCFC 250 kW w/CHP
Fuel Cell – PEM 10 kW w/CHP
Natural Gas Engine – 1 MW
Combustion Turbine – 5 MW
Diesel Engine – 500 kW
Diesel Engine – 500 kW
Diesel Engine – 200 kW
Diesel Engine – 1.5 kW
Solar Photovoltaic (50% Incent.) – 5 kW
Diesel Engine – 1 MW
Small Wind Turbine – 10 kW
Natural Gas Engine – 500 kW
Solar Photovoltaic – 500 kW
Natural Gas Engine – 100 kW
Diesel Engine – 7.5 kW
Solar Photovoltaic – 100 kW
Microturbine – 80 kW
Diesel Engine – 60 kW
Solar Photovoltaic – 5 kW
Microturbine – 30 kW
Diesel Engine – 30 kW
Central Station Comparison
Pulverized Coal – No Recovery (500 MW)
($0.044 - $0.045/kWh)
Combined-Cycle Gas Turbine (500 MW)
($0.06 - $0.08/kWh)
Coal Gasification (IGCC) – With Recovery (450 MW)
($0.061 - $0.075/kWh)
Retail Rate Comparison
Retail Rate Range
($0.07 - $0.22 or higher)
Depends on Load Factor, Rate Design, Utility
Retail Range
$0.00
$0.10
$0.20
$0.30
$0.40
$0.50
$0.60
$0.70
$0.80
$/kWh Cost of Energy

Source: EPRI, 2004.

2.7.13.5 Further Work

In its recent study on DG entitled *Distributed Energy Resources: Current Landscape and a Roadmap for the Future,* EPRI concludes the future could see DG playing an increasingly important role in

[42] Op. Cit., Rastler.
[43] Ibid.

the composition of power systems[44]. EPRI notes, however, that much work remains to be done "to reduce the costs of the technology, facilitate applications in concert with the needs of the grid, and remove policy barriers". Accordingly, EPRI offers a number of recommendations for advancing the role of DG, including working towards:

- Lowering total capital cost, improving reliability, and improving fuel flexibility
- Advancing cost and performance of energy storage technologies
- Advancing status of "plug and play" interconnection devices for larger DG applications
- Advancing economic tools and best practices are to help assess the technical and economic feasibility of incorporating DG into the transmission and distribution planning process
- Developing new grid designs to maximize the value of DG
- Developing more robust and sophisticated communication and protocols to enable control and dispatch of DG resources
- Verifying reliability through further standardization of DG products and systems pre-certification

Similarly, in 2002, the California Energy Commission issued a Distributed Generation Strategic Plan, in which it embraced the following 10 recommendations as a general framework for advancing its own vision that "distributed generation will be an integral part of the California energy system, providing consumers and energy providers with safe, affordable, clean, reliable, and readily accessible energy services"[45]:

- Adopt uniform technical standards for interconnecting distributed power to the grid
- Adopt testing and certification procedures for interconnection equipment
- Accelerate development of distributed power control technology and systems;
- Adopt standard commercial practices for any required utility review of interconnection
- Establish standard business terms for interconnection agreements
- Develop tools for utilities to assess the value and impact of distributed power at any point on the grid
- Develop new regulatory principles compatible with distributed power choices in competitive utility markets
- Adopt regulatory tariffs and utility incentives to fit the new distributed power model
- Establish expedited dispute resolution processes for distributed generation project proposals
- Define the conditions necessary for a right to interconnect

These and other considerations can help inform further work to better integrate DG into Ontario's supply mix and planning processes.

[44] Op. Cit, EPRI.
[45] California Energy Commission. *Distributed Generation Strategic Plan*. June 2002, Document No. P700-02-002.

2.7.14 Environmental, Cost and Risk Comparison of Resource Options

2.7.14.1 Summary Table of Environmental Ranks

The following tables summarize the environmental characteristics of all of the options analyzed.

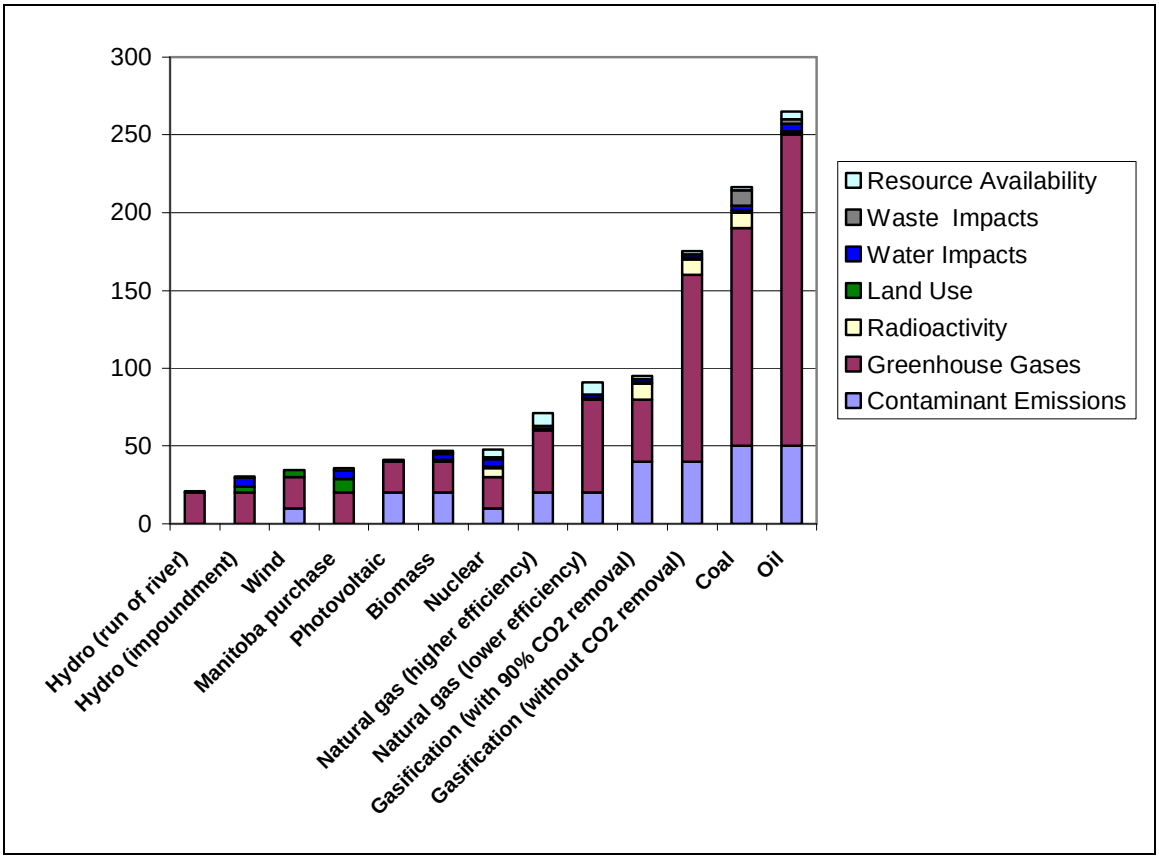
Table 2.7.56 – Comparison of Scored Environmental Impacts

	Contaminant Emissions	CO_2e	Radioactivity	Land Use	Water Impacts	Waste Impacts	Resource Availability	**Total Impact (Weighted)**
Hydro (run of river)	0	1	0	0	0	0	1	**21**
Hydro (impoundment)	0	1	0	4	5.5	0	1	**30.5**
Manitoba purchase	0	1	0	8.5	5.5	0	2	**36**
Wind	1	1	0	4.5	0	0	0	**34.5**
Biomass	2	1	0	1	4	1	1	**47**
Photovoltaic	2	1	0	1	0	0	0	**41**
Nuclear	1	1	6	1	4.5	1	5.3	**47.8**
Natural gas (single cycle)	2	3	0	1	2	0	8	**91**
Natural gas (combined cycle)	2	2	0	1	2	0	8	**71**
Natural gas (cogeneration)	2	2	0	1	2	0	8	**71**
Gasification (without CO_2 removal)	4	6	10	1	2	0	2	**175**
Gasification (with 90% CO_2 removal)	4	2	10	1	2	0	2	**95**
Coal	5	7	10	1	3.5	10	2	**216.5**
Oil	5	10	1	1	5	3	5	**265**

Note: The Total Weighted Impact is calculated by applying a weight of 10 to contaminant emissions, 20 to greenhouse gases, and 1 to all other categories. For further information, please see Part 2.6.

Source: SENES and OPA

Figure 2.7.8 – Comparison of Scored Environmental Impacts (Weighted)



Source: SENES and OPA

It will be seen that the scores, by and large, reflect popular expectations.

2.7.14.2 Cost Comparison

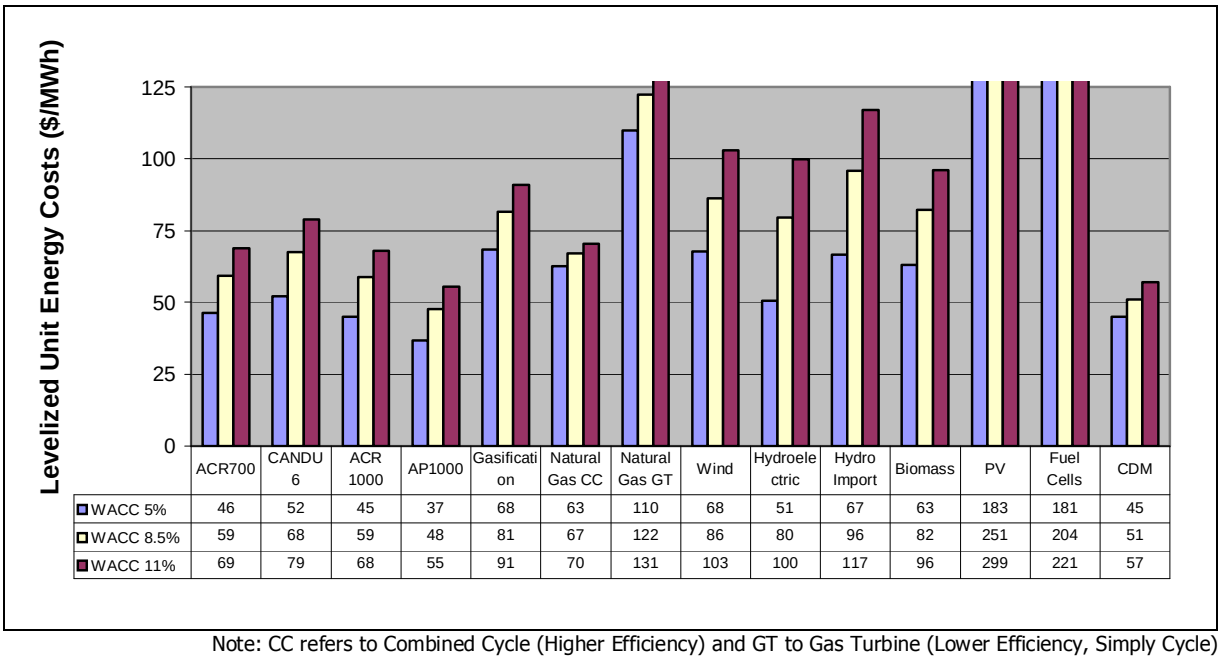
The costs of the options have been compared using their levelized unit energy costs. Levelized Unit Energy Cost (LUEC) is a cost measure that allows comparison of options with similar operating regimes. One option may be expensive to build but cheap to run compared to another option which is vice versa. Various options may have different patterns of expenditures, service lives and sizes. It is a single number expressed in c/kWh or $/MWh, and can be expressed in constant dollars or escalated dollars.

The LUEC methodology levelizes costs by an annuity method, which involves allocating costs in equal annual instalments over the operating life of the option in such a way as to give the same cumulative present value as the original expenditures. It is thus sensitive to discount factor used.

The LUEC is a useful tool for comparing the basic economics of various options. A more detailed accounting of costs is performed subsequent to screening the LUECs.

As explained in Part 2.6, OPA has evaluated its options using three discount rates (or weighted average costs of capital (WACC). Figure 2.7.9 provides a comparison of LUECs for each option. Gas and coal prices were respectively assumed as $8/MMBTU and $2.5/MMBTU. Capacity factors in all cases except the options shown were assumed as 85% except for: wind 30%, hydroelectric 45%, photovoltaic 30%, simple cycle gas 20%, biomass 50%.

Figure 2.7.9 – LUECs: Different Discount Rates



	ACR700	CANDU 6	ACR 1000	AP1000	Gasification	Natural Gas CC	Natural Gas GT	Wind	Hydroelectric	Hydro Import	Biomass	PV	Fuel Cells	CDM
WACC 5%	46	52	45	37	68	63	110	68	51	67	63	183	181	45
WACC 8.5%	59	68	59	48	81	67	122	86	80	96	82	251	204	51
WACC 11%	69	79	68	55	91	70	131	103	100	117	96	299	221	57

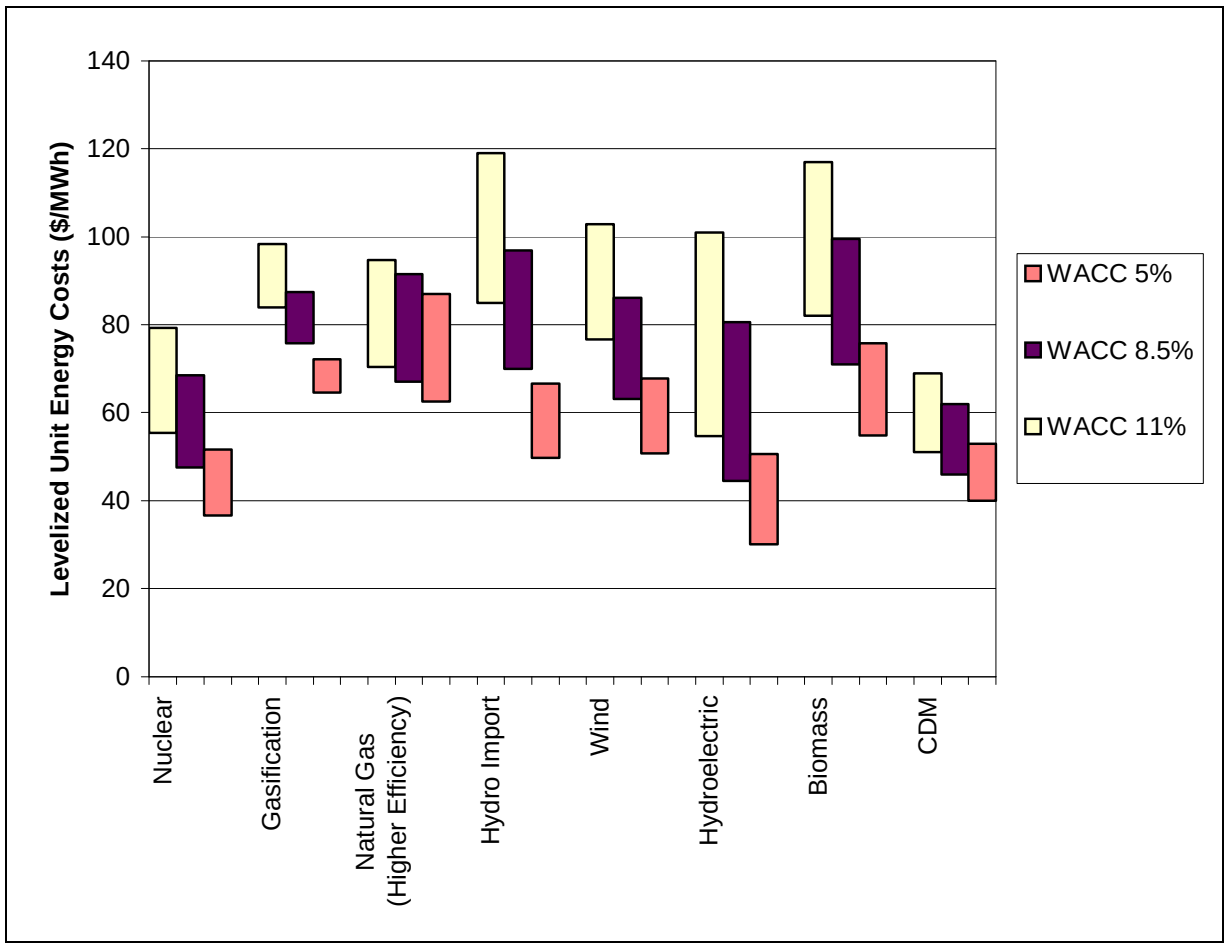
Note: CC refers to Combined Cycle (Higher Efficiency) and GT to Gas Turbine (Lower Efficiency, Simply Cycle)
Source: OPA

Figure 2.7.9 shows the lower LUECs resulting from a lower discount cost of capital. The nuclear, combined cycle and biomass options are seen to have the lowest LUECs, with somewhat larger LUECs for wind, gasification, purchases, and hydroelectric. Gas turbines are larger still, while photovoltaic and fuel cells are the highest.

The above figure shows the expected values, but much of the data has a range, and the values are last considered as falling within a range. Table 2.7.49 shows the parameter that was changed for each option to create the range. Figures 2.7.10 and 2.7.11 provide a range for the LUECs, split between base load, renewable, and peaking options. The high and low LUECs were obtained by varying a key variable for each option as indicated below.

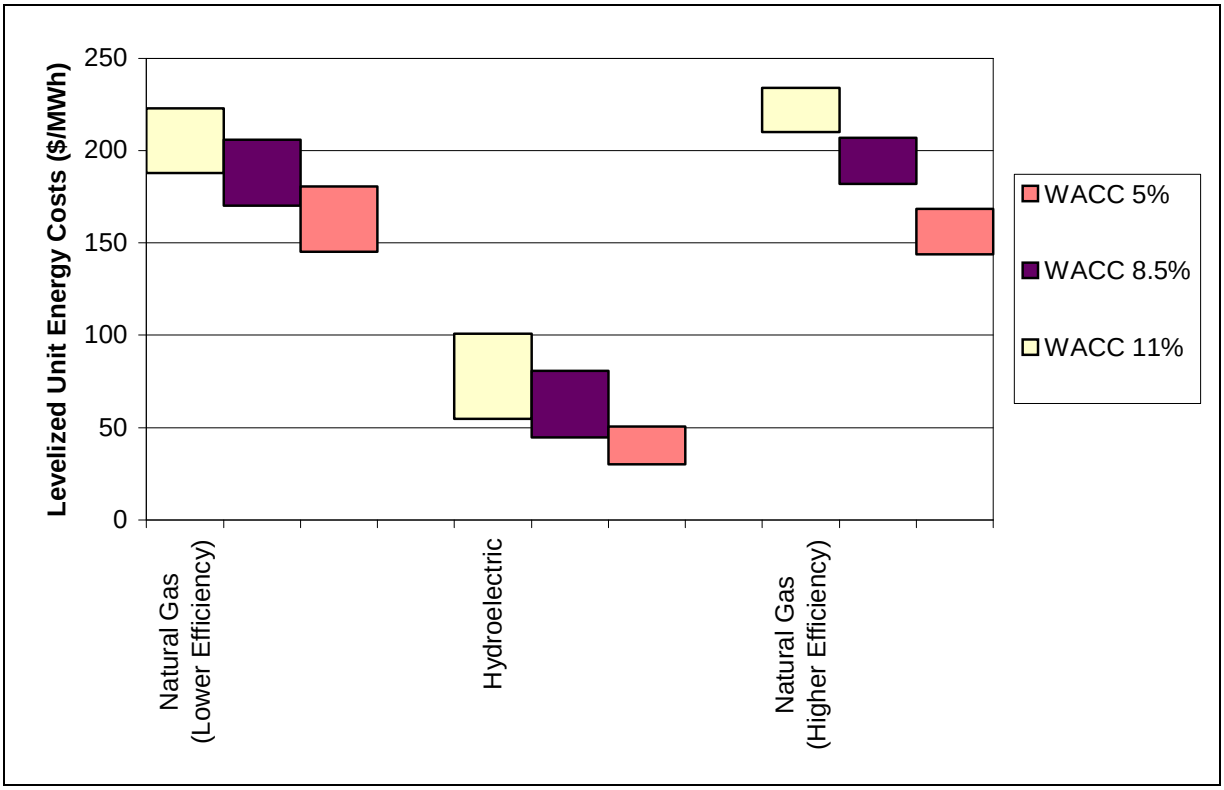
- Nuclear: highest and lowest cost technologies
- Gasification: coal price variation of plus/minus 15%
- Natural gas: gas price $8/MMBTU to $12/MMBTU
- Hydro Import: Lower capital cost at 70% of planning assumptions
- Wind: Capacity factor 30% to 40%
- Hydroelectric: Lower capital cost for refurbishments and extensions at 50% of new construction
- Biomass: Capacity factor 40% to 60%
- CDM: energy efficiency programs at various incentive levels

Figure 2.7.10 – LUECs: Base-load and Rewable Generation Options



Source: OPA

Figure 2.7.11 – Range of LUECs for Peaking

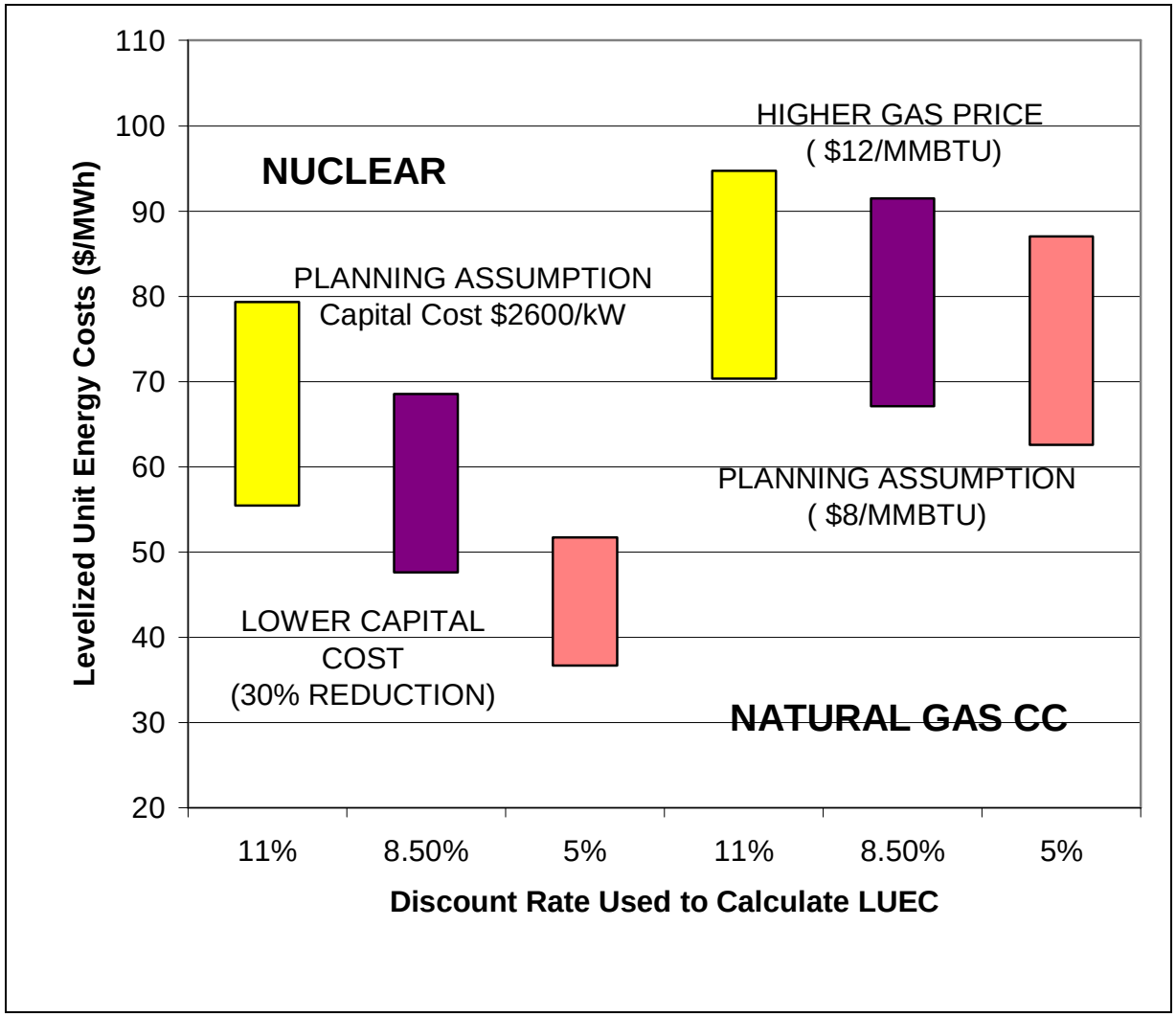


Source: OPA

Figure 2.7.10 shows that costs are very sensitive to the discount rate assumed and to natural gas prices and to the role the option plays in the integrated power system.

Figure 2.7.12 focuses on natural gas combined cycle and nuclear as these are two prime candidates for base-load supply.

Figure 2.7.12 – LUEC – Nuclear and Natural Gas Combined Cycle (CC)

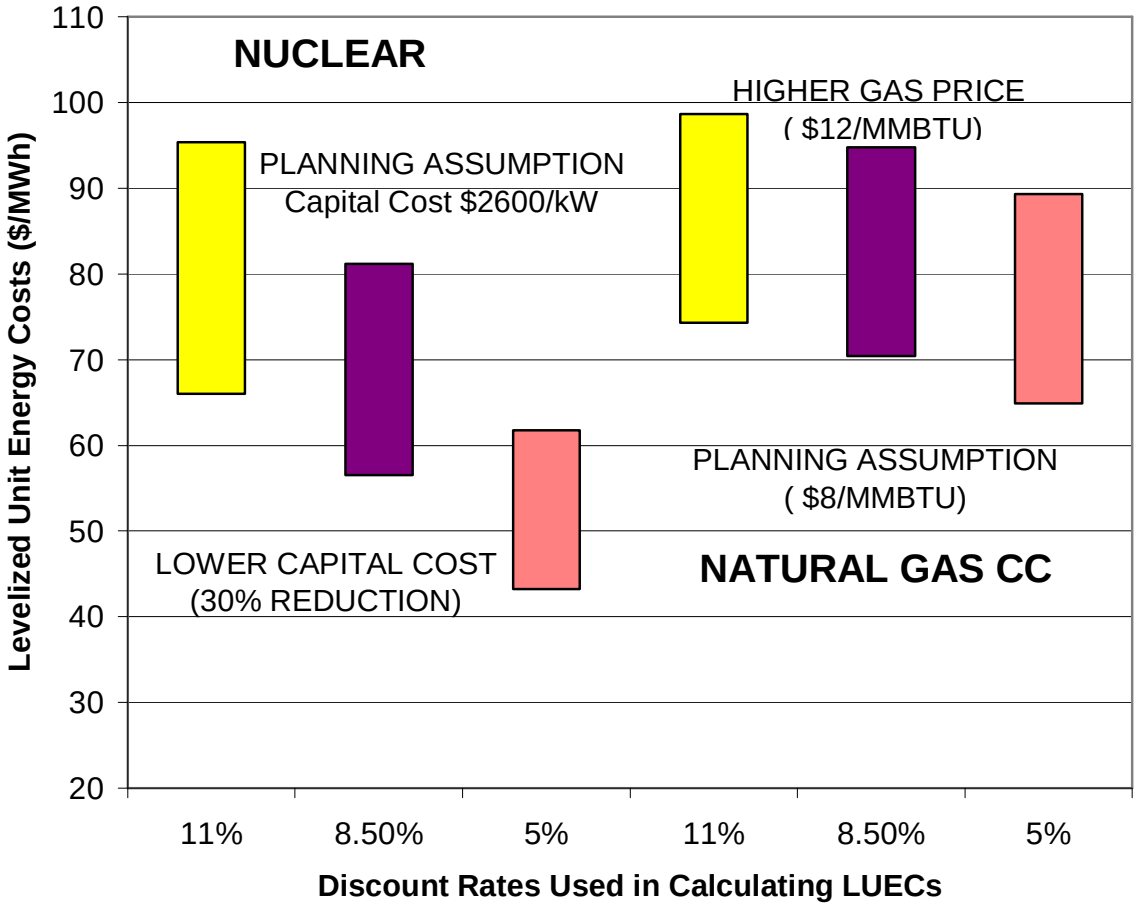


Note: Based on 85% Average Capacity Factor
Source: OPA

The results shown above illustrate the sensitivity to discount rate that particularly impacts capital intensive options such as nuclear and renewable.

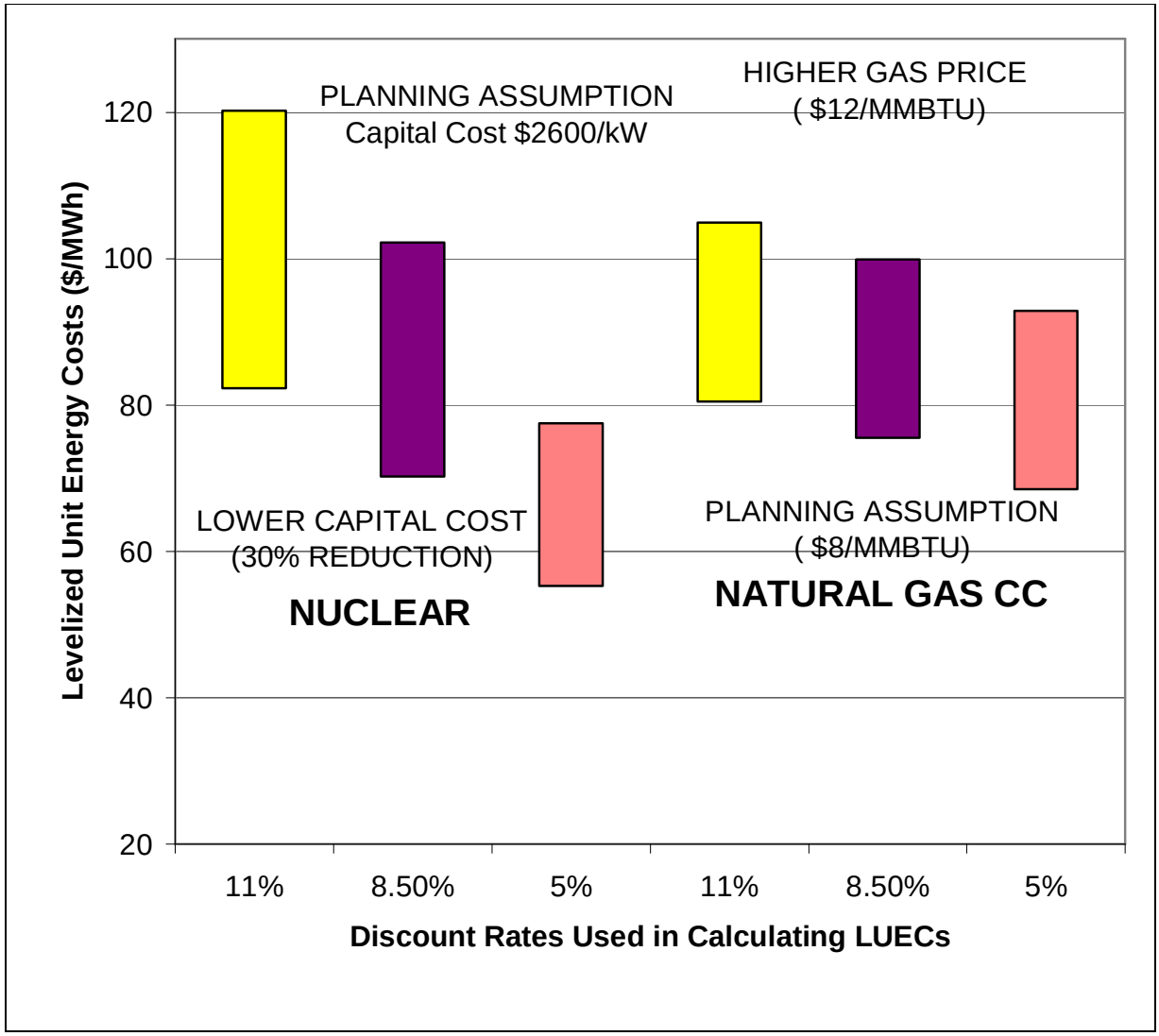
The following figure assumes base load operation. The following two figures show how the economics change if the options are used (or usable) less of the year.

Figure 2.7.13 – LUECs: Nuclear and Natural Gas Combined Cycle (CC) @ 70 ACF



Source: OPA , Note: Based on 70% Average Capacity Factor

Figure 2.7.14 – LUECs: Nuclear and Natural Gas CC @ 55 ACF



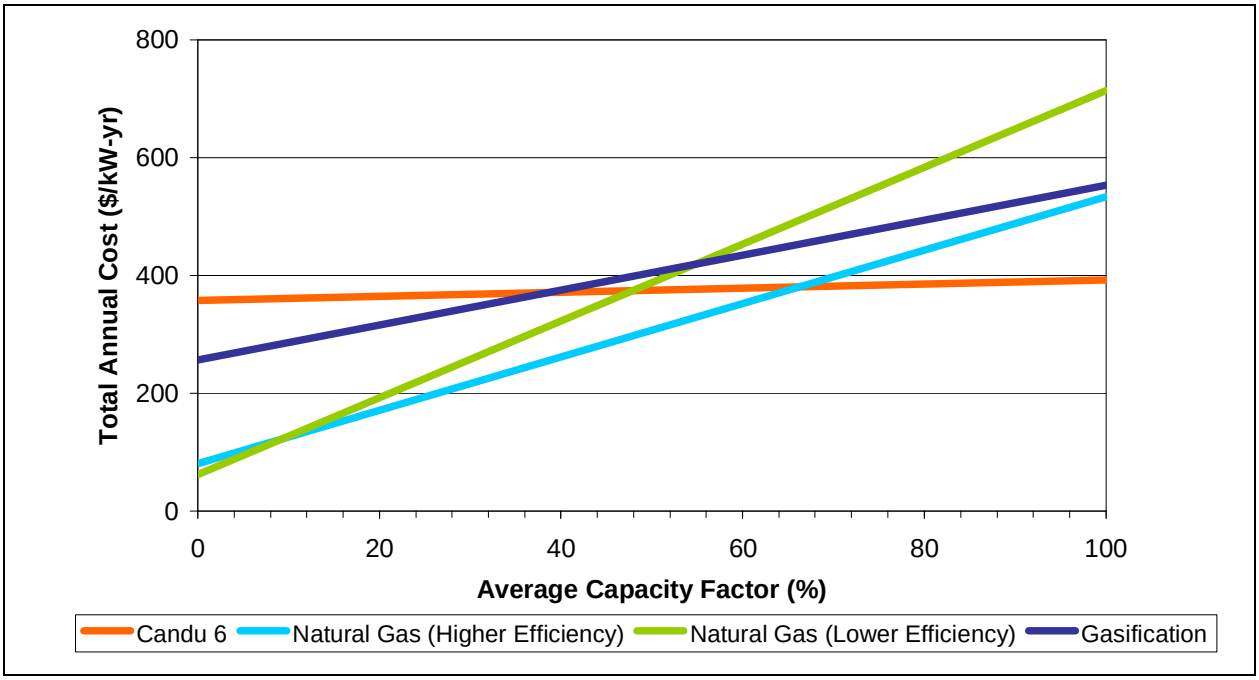
Source: OPA , Note: Based on 55% Average Capacity Factor

LUECs and the associated total annual cost can be used to determine the range of parameters under which one option is favoured over. The following examples illustrate breakeven points between two or more options when a specified set of parameters are varied and all other parameters are assumed unchanged.

Figure 2.7.15 provides the total annual cost for the nuclear combined cycle, simple cycle and gasification options for different capacity factors. The breakeven capacity factors where one option is economic over another are provided below. These figures assume an 11% discount rate.

- Simple cycle economic with ACF (average capacity factor) less than 10%
- Combined Cycle economic with ACF between 10% and 70%
- Gasification not economic at coal price at $2.5/MMBTU
- Nuclear economic with ACF greater than 70%

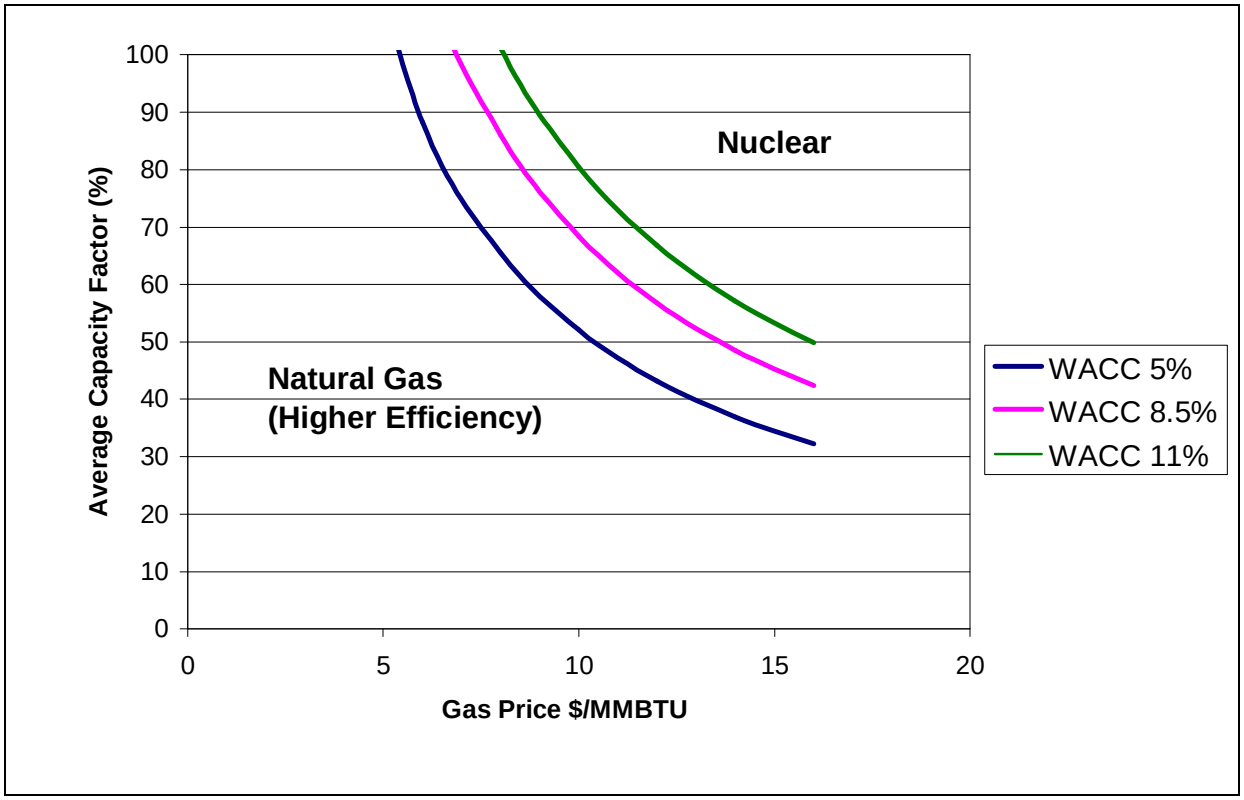
Figure 2.7.15 – Breakeven Analysis Based on Capacity Factor (Gasification includes sequestration)



Source: OPA

Figure 2.7.16 compares the nuclear and combined cycle options. Capacity factors for varying gas prices at which the two options would have the same LUEC were determined. The breakeven gas price where one option is economic over another is provided below.

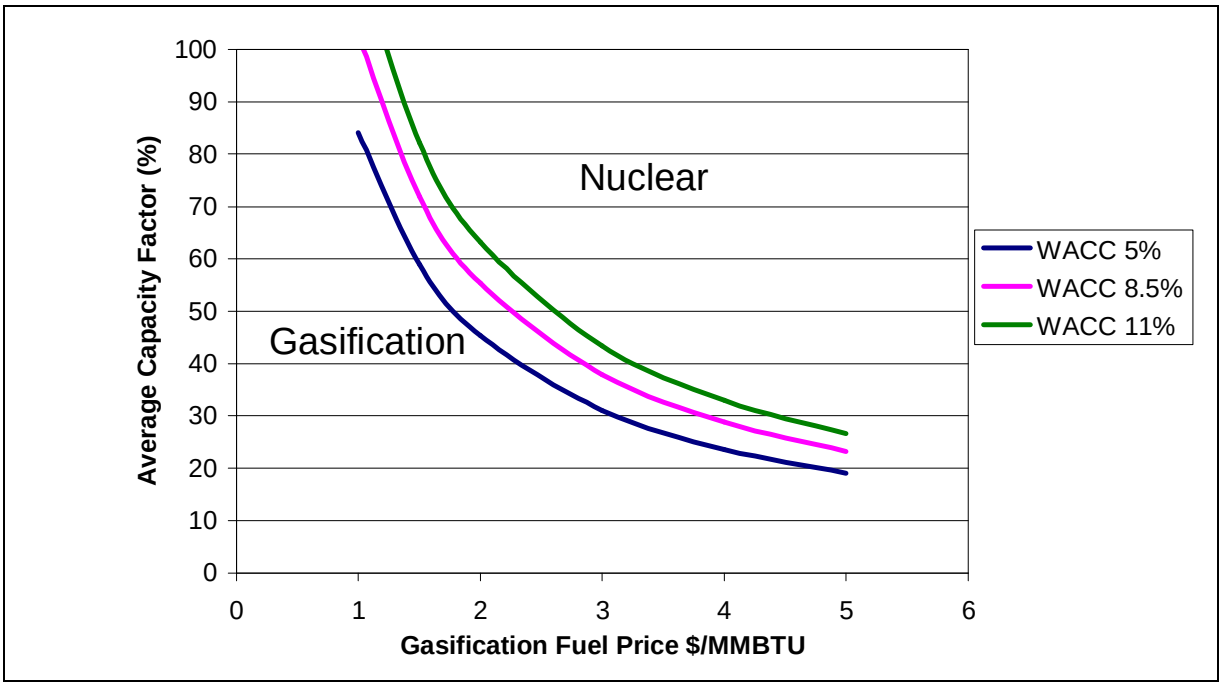
Figure 2.7.16 – Natural Gas Combined Cycle (CC) vs. Nuclear (Breakeven ACF)



Source: OPA

Figure 2.7.17 compares the nuclear and gasification options. Capacity factors for varying coal prices at which the two options would have the same LUEC were determined. The breakeven coal price where one option is economic over another is provided below. It can be seen that gasification is economic for base load operation with fuel price less than $1/MMBTU

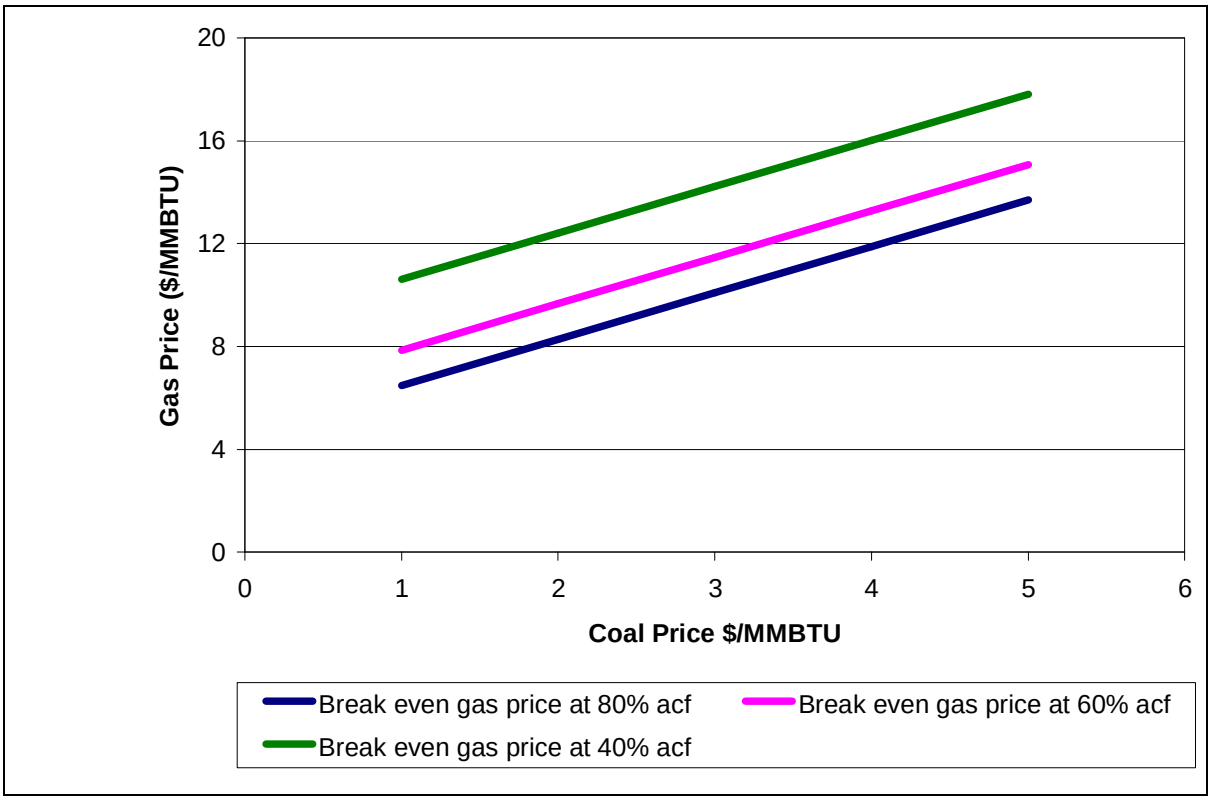
Figure 2.7.17 – Nuclear vs. Gasification (Breakeven ACF)



Source: OPA

Figure 2.7.17 compares the combined cycle and gasification options. Gas prices for varying gasification fuel prices at which the two options would have the same LUEC were determined for each of three different capacity factors. The breakeven coal and gas prices where one option is economic over another is provided below. It can be seen that, for example, if coal costs $2/MMBTU, gas must cost less than $8/MMBTU for combined cycle to be economic for base load operation (80% ACF).

Figure 2.7.18 – Natural Gas Combined Cycle vs. Gasification



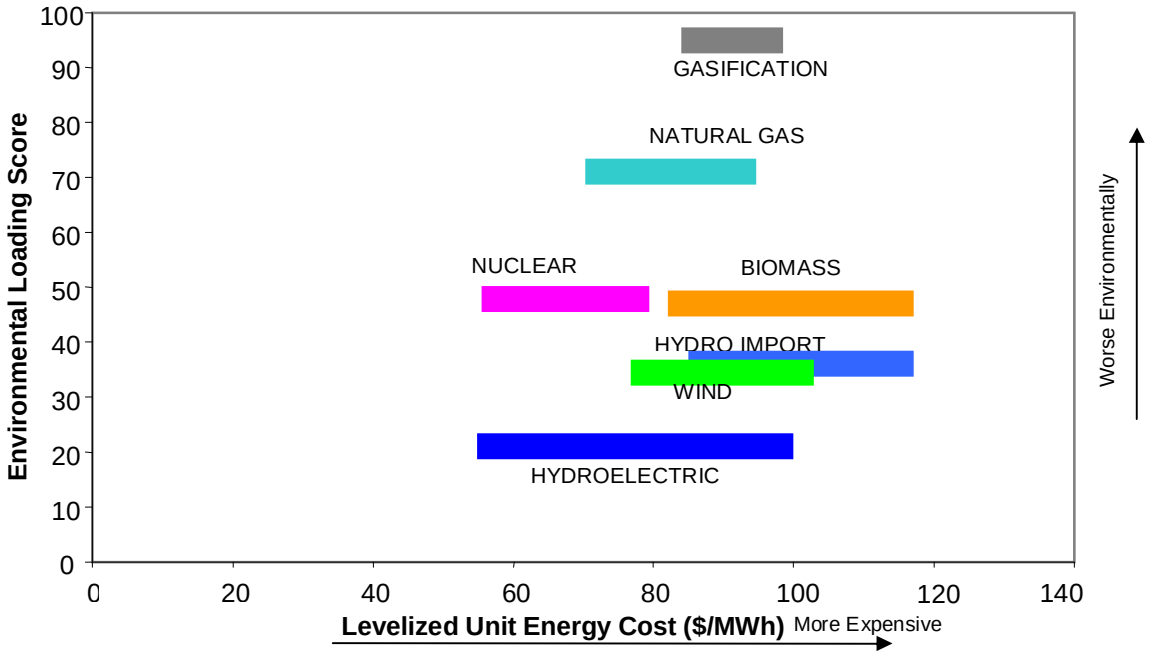
Source: OPA

2.7.14.3 Combined Environment, Economic and Risk Comparison

The figure below combines the results shown in the previous two sections.

The cost ranges cover the range of possible discount rate. Options toward the bottom left of the figure are preferred. It will be seen that those can include hydraulic, nuclear and purchased.

Figure 2.7.19 – Base-load Combined Environmental Scores and Cost Ranges



Source: OPA

2.8 Description of Scenarios and Portfolios

This Part outlines the resource and scenario assumptions developed and analyzed by OPA in preparing the supply mix advice.

2.8.1 Key Findings

- Five scenarios were constructed to illustrate possible futures
- Two portfolios of resource options were developed as alternative responses to each of the five scenarios
- Each portfolio was selected to illustrate the drivers and risks that are shaping Ontario's supply mix and integrated planning challenge
- Each portfolio was analyzed to understand cost, financial risk, and environmental impact
- The common elements assigned to most portfolios are:
  - 1,800 MW of conservation through energy efficiency and demand management
  - 5,000 MW of wind power
  - 1,500 MW of additional waterpower
  - 1,250 MW of out-of-province purchases
  - 500 MW of biomass generation
  - 40 MW of solar photovoltaic generation
  - 500 MW of fuel cell generation
  - 250 MW of gasification

2.8.2 Introduction

As described in Part 2.7, OPA undertook an extensive analysis of potential supply and conservation and demand management resources. Part 2.8 builds on this analysis by developing "packages" of resource options (portfolios), each of which is capable of meeting Ontario's supply needs to 2025. As the period to 2025 is uncertain with respect to a number of factors, OPA developed five scenarios to represent different possible futures, and developed two portfolios for each scenario.

The following sections begin with an outline of the role of each resource considered in Part 2.7 within OPA's supply mix planning assumptions. These assumptions informed the development of scenarios and portfolios that were analyzed from the perspectives of cost, financial risk, and environmental impact. The scenarios illustrate possible futures, while portfolios illustrate possible responses. The question of "what are the tools we have to work with" is addressed first, followed by a discussion of "what was done with those tools". The question of "how the tools work together" is addressed in Part 2.9.

2.8.3 Overview of Resource Assumptions

2.8.3.1 Conservation and Demand Management

Conservation and Demand Management (CDM) is a cornerstone of Ontario's long-term electricity future. OPA retained ICF Consulting to develop an estimate of the potential for CDM in Ontario. In its analysis, ICF employed an "experience-based" approach that looked at savings achieved elsewhere, as well as an "accounting-based" approach which looked at potential across the sectors that make up Ontario's economy. The work produced an estimated potential reduction in peak demand of between 1,500 MW and 4,000 MW. On a moderate demand day, the range would be roughly 1,000 MW to 3,600 MW. Because of the acknowledged difficulty in developing these figures, and for the purposes of supply planning, prudence dictates that the recommended supply mix rely on the lower set of figures for gains in energy efficiency until higher confidence is developed and the plan can then adapt. The portfolios described below assumed 1,500 MW of conservation through energy efficiency.

2.8.3.2 Wind Power

As discussed in Part 1.2, OPA observes that wind power holds the potential to provide for a considerable share of Ontario's longer-term energy needs. Based on analysis by Helimax Energy using data from the Ministry of Natural Resources and Hydro One Networks, the theoretical wind potential in Ontario is estimated to be well over 600,000 MW. This estimate considers onshore areas where average annual wind velocity is greater than 6.5 meters per second at 80 meters above ground level, and is net of constraint areas such as roads, parks, houses and buffers. The analysis assumes 5 MW of capacity per suitable km^2 of area. As roughly 95% of the potential is located north of the 50^{th} parallel of latitude, it is effectively out of the reach of the existing Hydro One Networks transmission system. However, the analysis shows that 29,000 MW of wind power potential exists south of the 50^{th} parallel. Of this potential, 7,000 MW lies within 10 km of high-voltage transmission lines, and almost 3,000 MW lie within 5 km of distribution stations. These numbers are not additive, as some wind areas are situated within both the 10 km distance to transmission and the 5 km distance to distribution.

While these numbers are large, further work is required to assess the implications of integrating large amounts of wind power into Ontario's power system, including implications on regulation, load following, and operating reserve requirements.

Regulation refers to the requirement to meet changes in system demand on a minute-by-minute or even second-by-second basis. While it is anticipated that impacts on regulation will be relatively small, it will be prudent to examine the issue on an ongoing basis as more data becomes available from new proponents.

Load following relates to maintaining the supply and demand balance on a 1-hour to 1-day timeframe. Some increases in load following requirements can be expected as more wind resources are added. As in the case of regulation, further analysis conducted on an ongoing basis will be required to assess the requirements and how to best meet them. Greater coordination between wind and hydroelectric production scheduling is one means to enhance load following capability and warrants more study.

Operating reserve requirements refer to the generation capacity or load reduction capacity that can be called upon on short notice to restore a balance between supply and demand, in the event of an unexpected load increase or supply outage. It is anticipated that at some point in time, the potential 5 - or 10-minute interval change in wind output could rise to the point where it would exceed the current first contingency level of about 900 MW, which is the basis for determining Ontario's 10-minute and 30-minute operating reserve requirements. The exact "tipping point" point for this possibility is not known at present, but can be determined through a combination of experience and forward-looking analysis. Experience with wind power in other jurisdictions, as well as initial studies prepared in Ontario, serve as good starting points for addressing all of the above issues.

The portfolios described below assume 5,000 MW of wind power by 2025. This represents a planning assumption rather than a prescription. It is judged a prudent level, given that the potential integration implications of greater amounts have not yet been fully assessed in the Ontario context. Once the assessments have been carried out, future supply plans will help ensure the adequate provision of the requisite services. Ultimately, the actual amount of wind power potential that will be harnessed in Ontario over time will be shaped by a variety of additional factors, including cost, acceptability to Ontarians, and public policy.

2.8.3.3 Water Power

Although Ontario developed most of its large waterpower sites early in the 20th century, many smaller sites still exist. OPA's analysis, based on data from the Ministry of Natural Resources, identifies 190 sites in Ontario with a technical potential of approximately 7,500 MW of additional waterpower. Of this potential, approximately 1,500 MW is estimated to be available in areas not protected from development or subject to agreements with First Nations. Using transmission and distribution system data obtained from Hydro One Networks, OPA observes that most of this 1,500 MW is within 5 km of a transmission line or distribution station. Ontario's hydroelectric potential is described in Part 3.6.

The portfolios described below assume 1,500 MW of additional waterpower, not including potential out-of-province purchases.

2.8.3.4 Biomass

The range for biomass potential in Ontario is wide, from a few hundred to several thousand megawatts. The largest share is theoretically in the forestry sector. Two constraints are dwindling forest resources and the cost of collecting material and transporting it to generating facility locations. There are also agricultural opportunities for crop residue and animal waste. Municipal solid waste incineration, landfill gasification, and wastewater treatment gas are other potential sources. The driver to exploit these resource options is likely to be pressures on and loss of waste disposal sites. The portfolios described below assume 500 MW of biomass generation.

2.8.3.5 Photovoltaic

Solar power has the advantage of using a free resource, has modularity that makes it amenable for distributed applications, is coincident with the summer peak, and has significant potential for technological and cost improvement. While it is estimated that photovoltaic costs have declined by 20% for each doubling of world-wide installed capacity,[1] high costs remain a challenge at the present time. Further cost improvements are expected to arise from, among other things, reductions in the cost of materials, design, processes, inverters and balance-of-system components. Jurisdictions including Japan, Germany and California have implemented supportive financial programs to promote photovoltaic power. These jurisdictions are now among the highest photovoltaic producers and users in the world.[2]

The Canadian Solar Energy Industries Association suggested a potential for up to 40 MW of photovoltaic power in Ontario by 2010. The portfolios described below assume 40 MW of photovoltaic generation.

2.8.3.6 Purchases from Neighbours

While Ontario developed its feasible large waterpower sites long ago, its neighbours Manitoba and Newfoundland and Labrador, still have waterpower resources that could be developed and the output exported to Ontario. Opportunities for non-renewable energy resources such as nuclear, natural gas, or coal fired generation also exist in the United States. The disadvantages to this include the long distances from the generation sites to load centres in Ontario and attendant costs of transmission connections. There are also major approval hurdles to building the new transmission in Ontario. However, if the lines were built they could form part of a Canadian east-west grid and open up additional opportunities for import and trade. The portfolios described below assume 1,250 MW of out-of-province purchases.

[1] REN21 Renewable Energy Policy Network. *Renewables 2005 Global Status Report*. Washington DC: Worldwatch Institute.
[2] David Suzuki Foundation. *Smart Generation: Powering Ontario with Renewable Energy*. 2004.

2.8.3.7 Fuel Cells

Benefits of fuel cells include modularity, amenability to combined heat and power applications, and efficient use of natural gas as a fuel source. They are attractive options for distributed applications both in densely populated and remote centres, as well as for promoting a strategy that would see natural gas employed as efficiently as possible, and only for select applications. The portfolios described below assumed 500 MW of fuel cell generation or other distribute generation sources.

2.8.3.8 Gasification

Advantages of gasification include the lower emissions relative to burning the fuel directly and the lower price volatility of various possible fuels, including coal, related to that of natural gas. A potential longer-term benefit is carbon dioxide sequestration (and reuse). Costs for gasification are still high and as described in Part 3.8 it is not yet a widely-used and mature technology, at least where coal is the fuel source. Gasification of coal is not likely to be acceptable in Ontario without carbon dioxide sequestration, and that is not a developed option at this time. That may well change over the next 20 years and gasification could make an appearance in Ontario's supply mix in the future. The portfolios described below assume 250 MW of gasification, but no sooner than 2014-2015.

2.8.3.9 Other Resources

More conventional supply resources were also included in the portfolios analyzed during the development of the supply mix advice. These include existing waterpower and natural gas/oil. It was assumed that existing waterpower and natural gas/oil resources would remain in service and be available throughout the 20-year study period. However, as noted in Part 2.5, this assumption represents a significant planning uncertainty due to observed limitations on the availability of waterpower during Ontario's summer peak period, as well as the possible loss over the mid-term of natural gas-fired capacity currently provided by a number of Non-Utility Generators (NUGs) in Ontario. New oil-fired generation was not considered in the analysis. New natural gas-fired generation was included in the portfolios to a limited degree. As discussed in Part 1.2, it is the OPA's view that Ontario's supply mix should not include significantly more natural gas than has already been contemplated by recent procurement initiatives and existing generating stations. Accordingly, the portfolios attempt to target the role of new natural gas-fired generation to the extent possible.

Existing nuclear resources were included in the portfolios, as were potential refurbishments and/or new build. Coal was considered in the background of the supply mix analysis because it is a significant part of the present supply mix and because delays may arise in its replacement.

2.8.4 Description of Scenarios and Portfolios

The following pages present five scenarios which illustrate a variety of possible futures. Two portfolios are presented for each scenario. Each portfolio represents a type of response to the scenario.

- **Scenario 1** illustrates a future in which all expected procurements, new renewable and conservation resources, and out-of-province purchases materialize.
- **Scenario 2** illustrates a future in which fewer resources materialize, including procurements, new renewable resources, and out-of province purchases.
- **Scenario 3** illustrates a future in which the full replacement of a small number of Ontario's coal-fired units is unavoidably delayed.
- **Scenario 4** illustrates a future where demand growth is higher than expected, but where the contribution of conservation and efficiency is also higher.
- **Scenario 5** illustrates a future which sees a higher success in capturing conservation and efficiency potential.

Each portfolio consists of a number of resources and options to meet Ontario's electricity requirements over time. Resources in this sense include generation and conservation and demand management, while options include early actions to enable flexibility in the face of an uncertain future, including flexibility to take advantage of future opportunities. In practice, portfolios can be adjusted as greater clarity is gained about how the future is actually unfolding. New resources and options can be added, while others can be removed.

The portfolios presented here were chosen to illustrate the various drivers and risks that are shaping Ontario's supply mix and integrated planning challenge, as well as how those drivers and risks might be addressed. The portfolios have been analyzed from the perspective of cost, financial risk, and environmental impact. The results of this analysis are discussed in Part 2.9.

Most of the portfolios described below share the following common elements:

- Approximately 1,800 MW of conservation and demand management by 2025
- 5,000 MW of installed wind resources by 2025
- 1,500 MW of new hydroelectric resources by 2025
- 1,250 MW of firm renewable purchases from outside of the province by 2025
- 500 MW of biomass resources by 2025
- 500 MW of new fuel cell resources by 2025
- 40 MW of new photovoltaic resources by 2025
- 250 MW of gasification generation no sooner than 2014
- All of the procurements outlined in Part 2.5
- All existing hydroelectric and natural gas/oil-fired resources (which are assumed to remain in service throughout the study period)

- A base forecast of future demand having approximately 0.9% energy growth and 1.3% peak demand growth per year.

For the purposes of this study, wind capacity has been derated to 10% of its nominal rating to reflect its contribution towards meeting peak demand. Similarly, hydroelectric capacity has been derated to 90% of its nominal rating, while biomass has been derated to 60%. These are planning assumptions meant to reflect less than full availability at the summer peak, and are consistent with the way the IESO considers resource availability during summer peak.

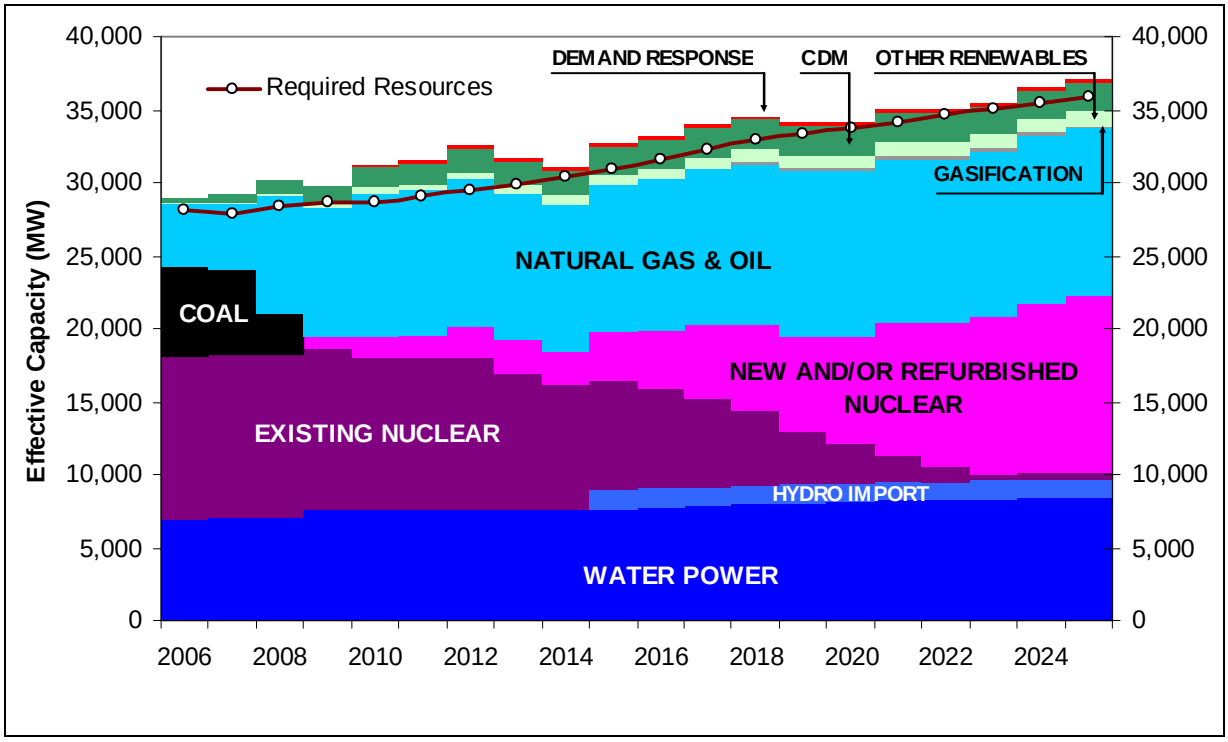
In view of the above, the 5,000 MW of wind resources identified above provide 500 MW of peak demand meeting capability, also known as "effective" capacity (as opposed to installed capacity or nominal capacity). Likewise, the 1,500 MW of new hydroelectric resources and 7,756 MW of existing hydroelectric resources provide, respectively, 1,350 MW and 6,980 MW of effective capacity. The 500 MW of biomass provide 300 MW of effective capacity. All summary figures presented in the sections below reflect these capacity deratings, except where otherwise indicated. In addition, natural gas/oil, natural gas, existing coal, and nuclear have been derated to 70%, 96%, 95%, and 98%, respectively.

2.8.4.1 Scenario 1, Portfolio 1A

In this portfolio, most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering, are refurbished or replaced as they reach the end of their estimated service lives between 2013 and 2025. All of the common elements outlined above are included. The entirety of Ontario's coal-fired fleet is removed from service and replaced by 2009.

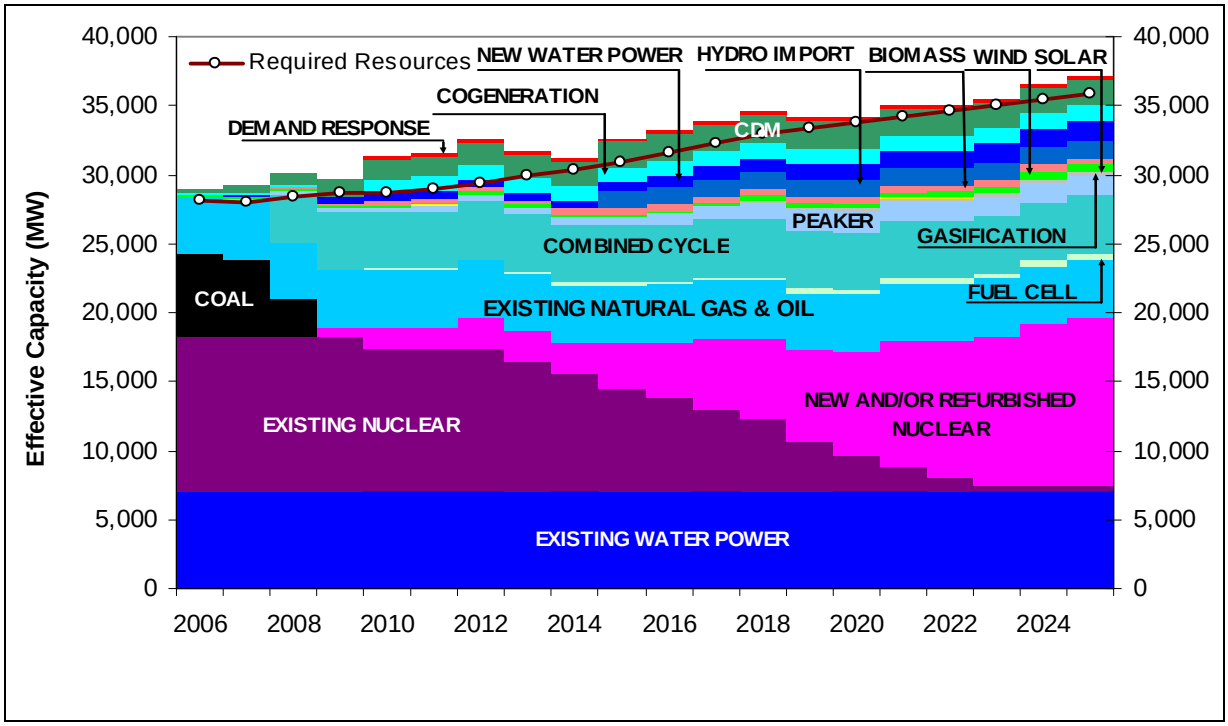
Figure 2.8.1 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.2. Energy production associated with the portfolio is shown in Figure 2.8.3. Figure 2.8.4 outlines the portfolio's composition at the year 2025. Tables 2.8.1 and 2.8.2 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.1 – Portfolio 1A



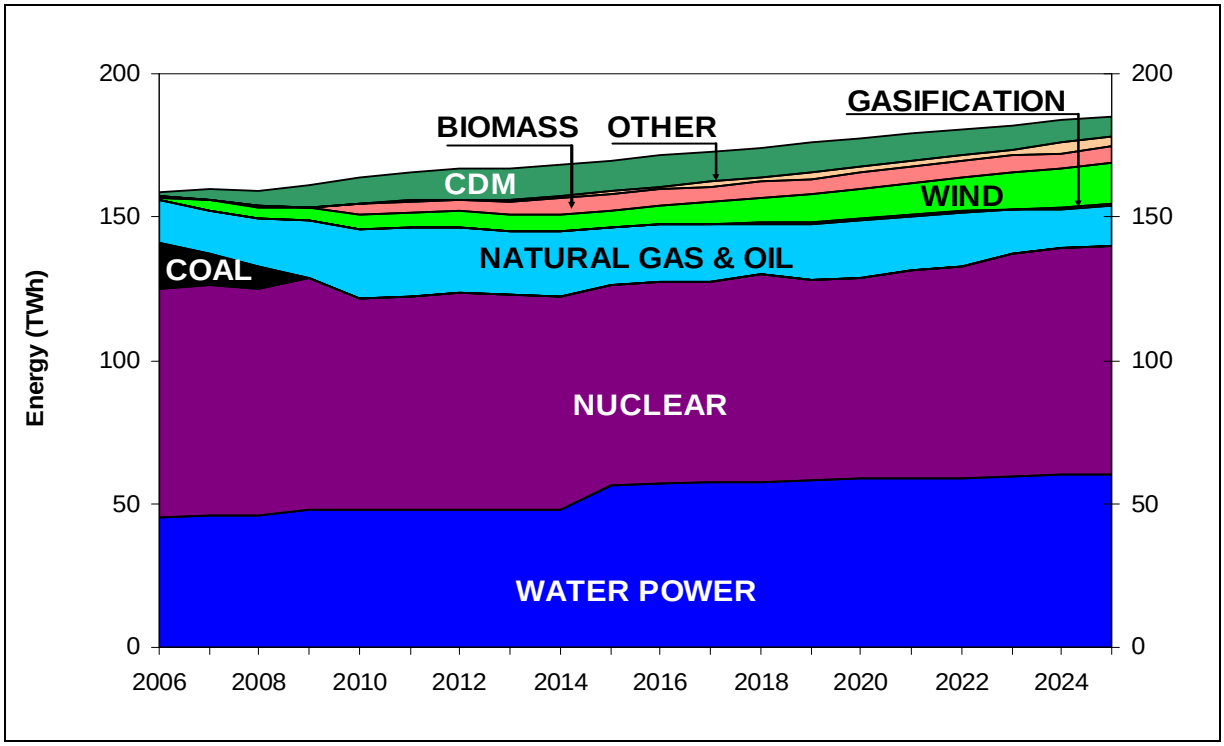
Source: OPA

Figure 2.8.2 – Portfolio 1A: Higher Resolution



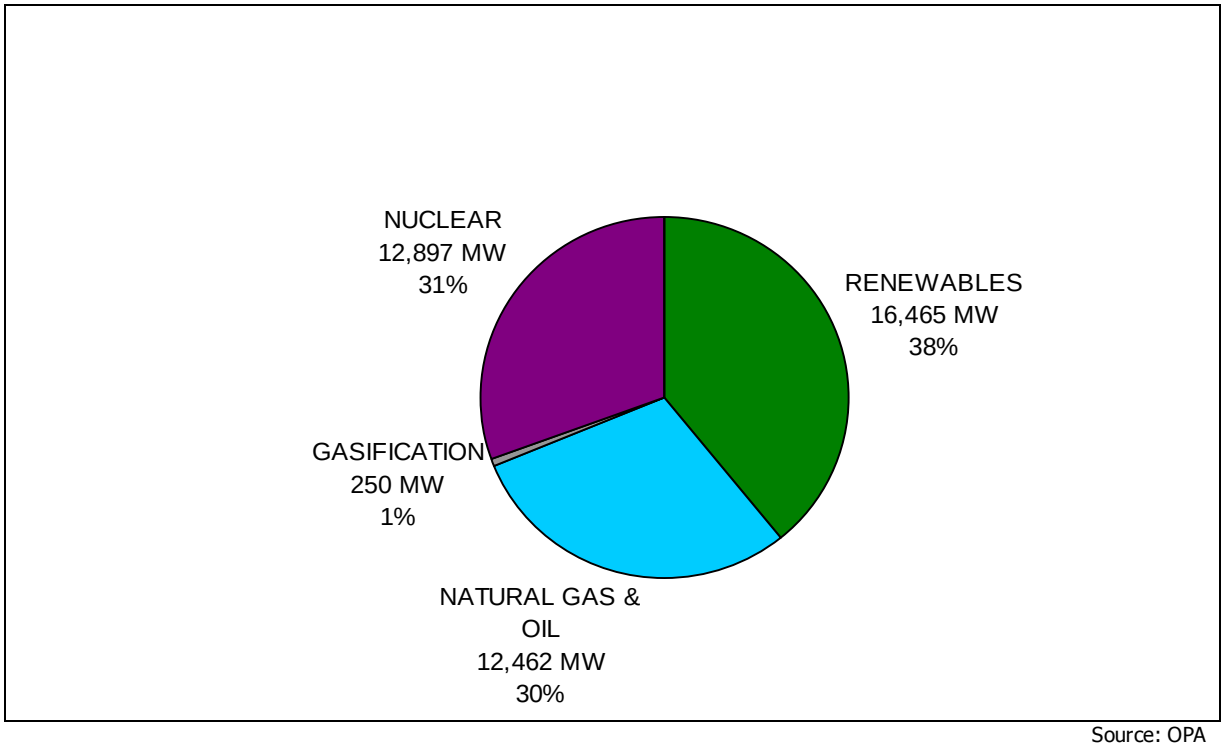
Source: OPA

Figure 2.8.3 – Portfolio 1A: Energy



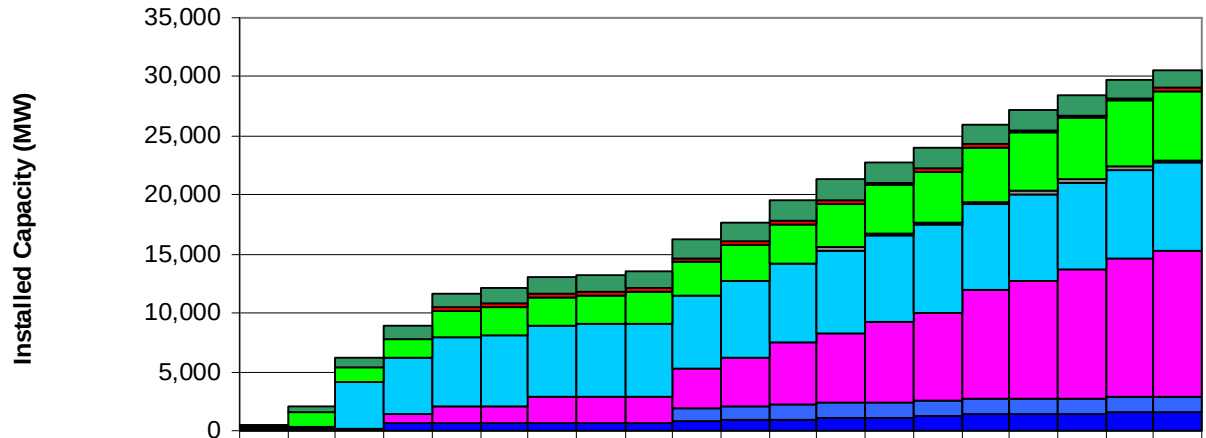
Source: OPA

Figure 2.8.4 – Portfolio 1A: Composition at 2025 (Installed)



Source: OPA

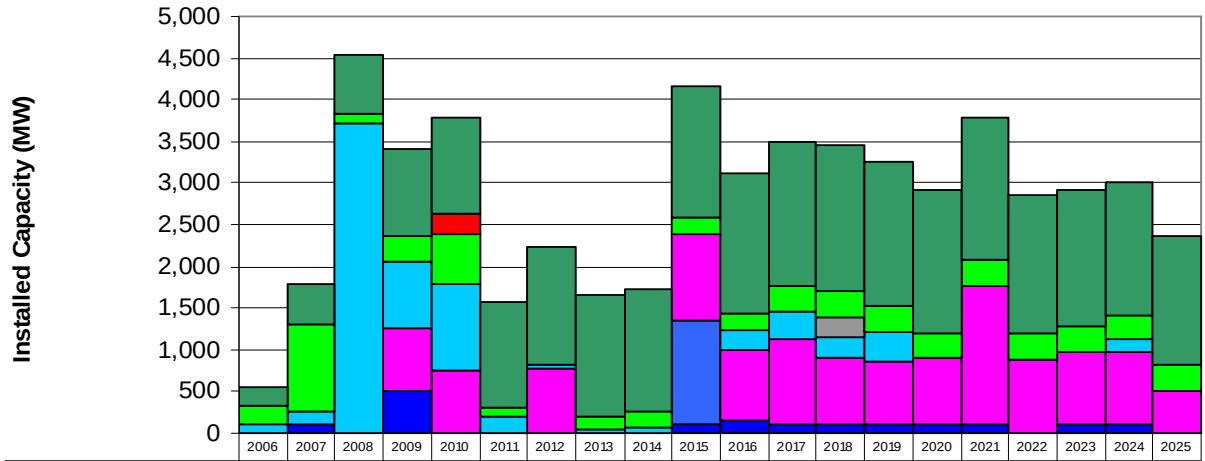
Table 2.8.1 – Portfolio 1A: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,700	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250
Natural Gas& Oil	117	272	3,992	4,786	5,826	6,026	6,066	6,106	6,166	6,166	6,416	6,746	6,996	7,346	7,346	7,346	7,346	7,346	7,486	7,486
New and/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	5,979	6,749	7,546	9,224	10,105	10,986	11,867	12,382
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	121	121	629	629	629	629	629	629	729	879	979	1,079	1,179	1,279	1,379	1,379	1,479	1,579	1,579

Source: OPA

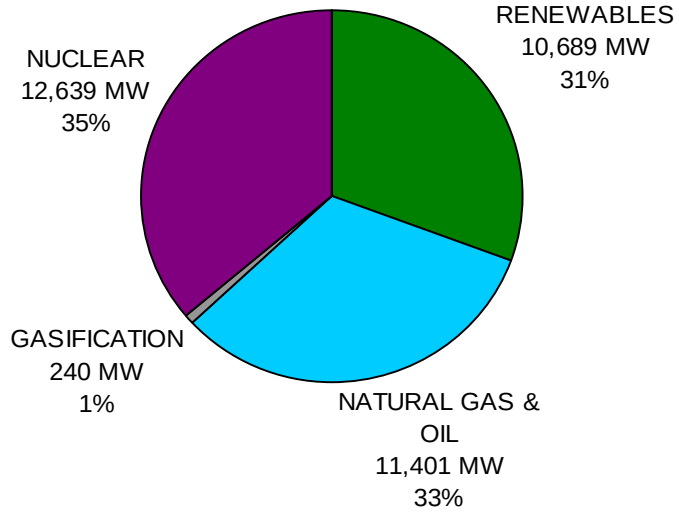
Table 2.8.2 – Portfolio 1A: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	150	200	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	250	0	0	0	0	0	0	0
Natural Gas& Oil	117	155	3,720	794	1,040	200	40	40	60	0	250	330	250	350	0	0	0	0	140	0
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	797	770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	508	0	0	0	0	0	100	150	100	100	100	100	100	0	100	100	0

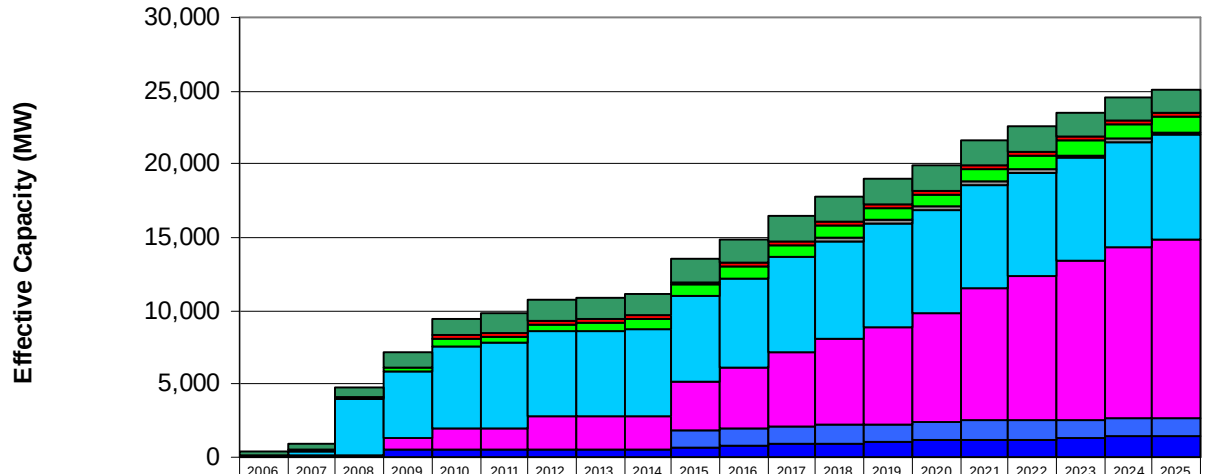
Source: OPA

Figure 2.8.5 – Portfolio 1A: Composition at 2025 (Effective)



Source: OPA

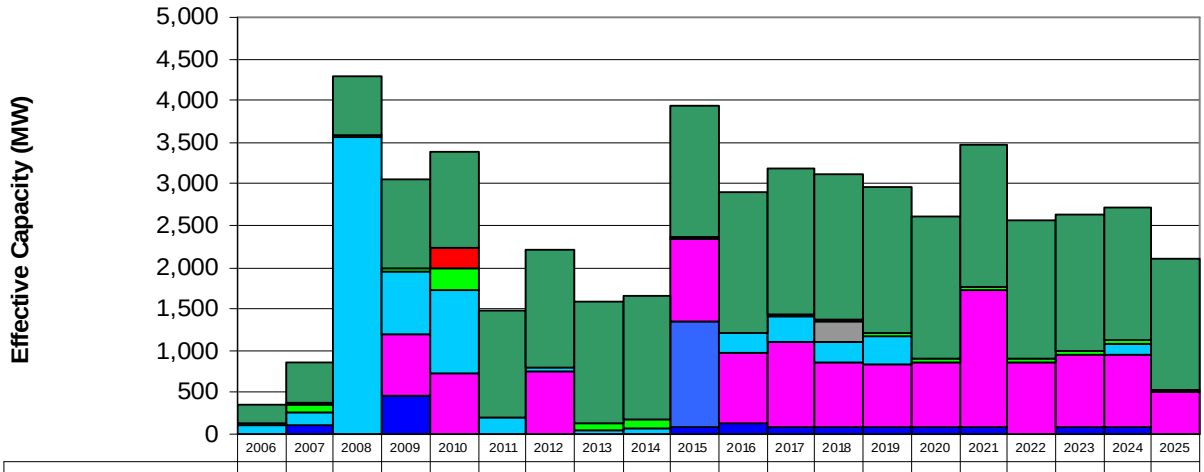
Table 2.8.3 – Portfolio 1A: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	668	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240
Natural Gas & Oil	112	261	3,832	4,595	5,593	5,785	5,823	5,862	5,919	5,919	6,159	6,476	6,716	7,052	7,052	7,052	7,052	7,052	7,187	7,187
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	5,859	6,614	7,395	9,040	9,903	10,766	11,630	12,134
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	108	108	566	566	566	566	566	566	656	791	881	971	1,061	1,151	1,241	1,241	1,331	1,421	1,421

Source: OPA

Table 2.8.4 – Portfolio 1A: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	90	120	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	240	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	3,571	762	998	192	38	38	58	0	240	317	240	336	0	0	0	0	134	0
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	781	755	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	0	90	135	90	90	90	90	90	0	90	90	0

Source: OPA

Table 2.8.5 – Portfolio 1A: Capacity at 2010, 2015, 2020, and 2025

1A Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	8,019	9,604	10,239	10,689
Natural Gas & Oil	9,808	10,134	11,267	11,401
Gasification	0	0	240	240
Nuclear	11,884	10,797	10,131	12,639
Coal	0	0	0	0
Total	31,262	32,608	34,166	37,068

1A Installed Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	10,680	12,685	14,635	16,465
Natural Gas & Oil	10,802	11,142	12,322	12,462
Gasification	0	0	250	250
Nuclear	12,127	11,017	10,338	12,897
Coal	0	0	0	0
Total	35,161	36,918	39,834	44,173

Source: OPA

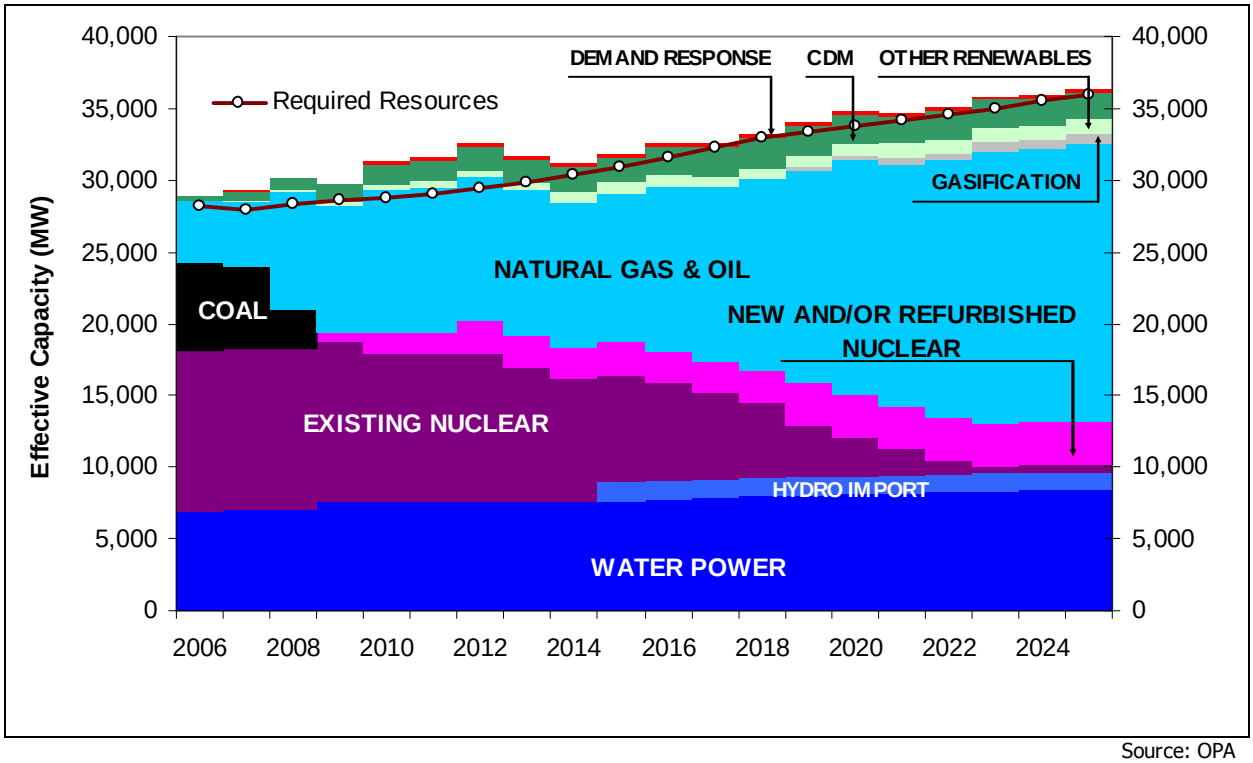
2.8.4.2. Scenario 1, Portfolio 1B

In this portfolio, most of Ontario's nuclear units are retired as they reach the end of their estimated service lives. Bruce nuclear units 1 through 4 are kept in service, reflecting the recent agreement between the government of Ontario and Bruce Power for the restart and refurbishment of the Bruce A facility. One unit at Pickering is assumed not to reach the end of its service life within the study period. Total installed nuclear capacity at 2025 is approximately 3,500 MW. The entirety of Ontario's coal-fired fleet is removed from service and replaced by 2009.

Once all of the common elements outlined in section 2.8.4 are added, the remaining resource gap is filled with approximately 9,300 MW of natural gas-fired generation and approximately 500 MW of additional gasification.

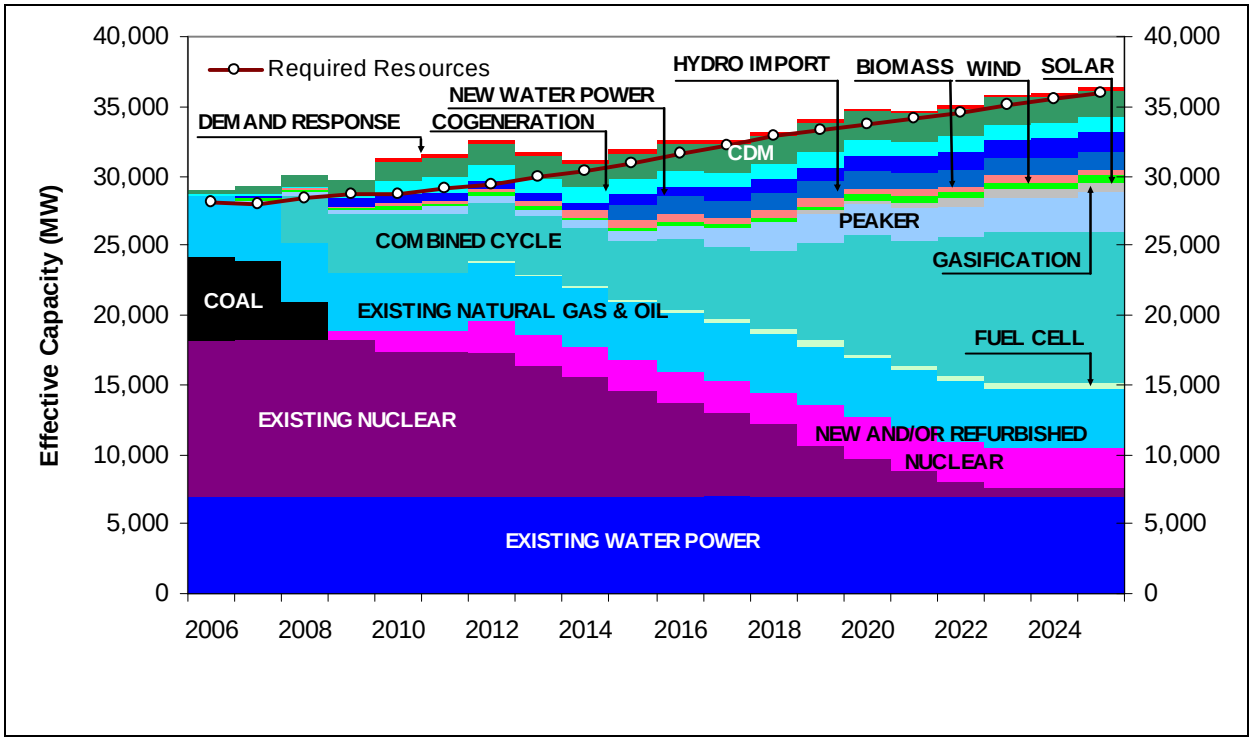
Figure 2.8.6 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.7. Energy production associated with the portfolio is shown in Figure 2.8.8. Figure 2.8.9 outlines the portfolio's composition at the year 2025. Tables 2.8.6 and 2.8.7 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.6 – Portfolio 1B



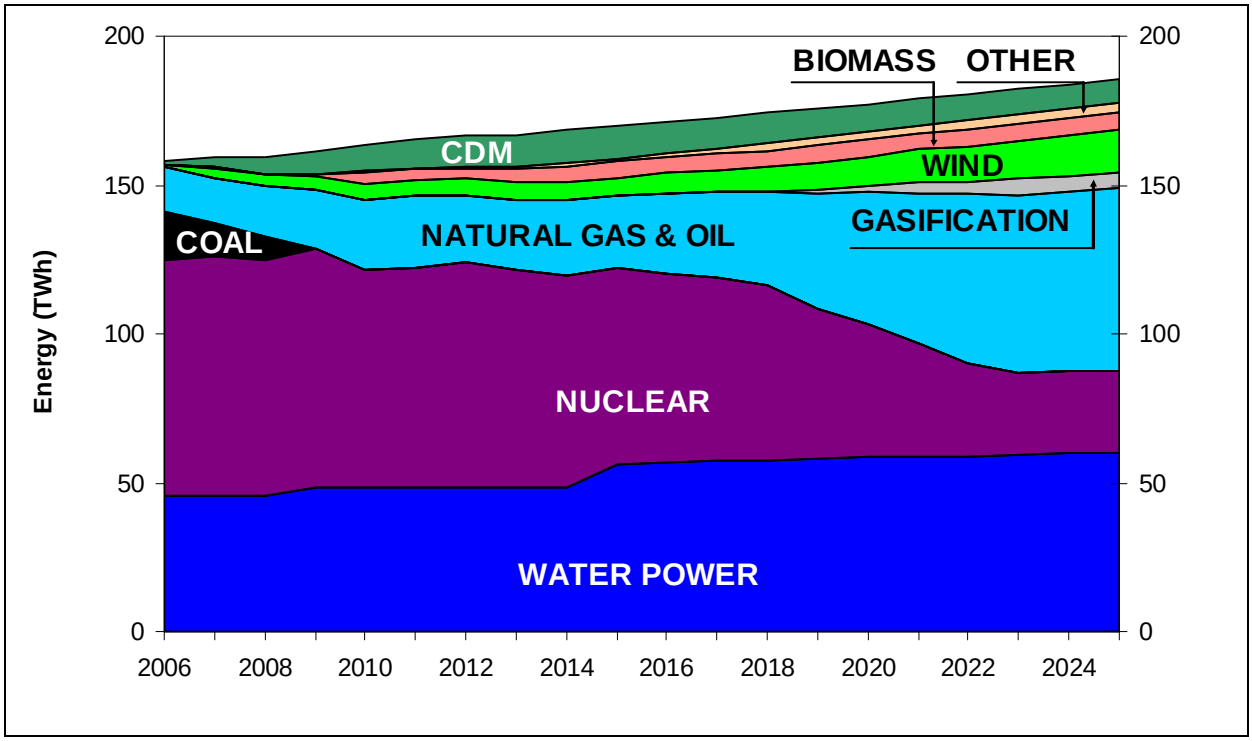
Source: OPA

Figure 2.8.7 – Portfolio 1B: Higher Resolution



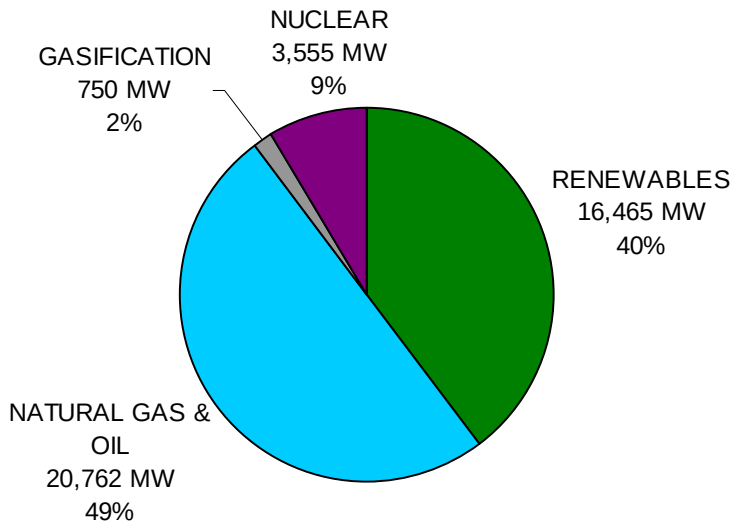
Source: OPA

Figure 2.8.8 – Portfolio 1B, Energy



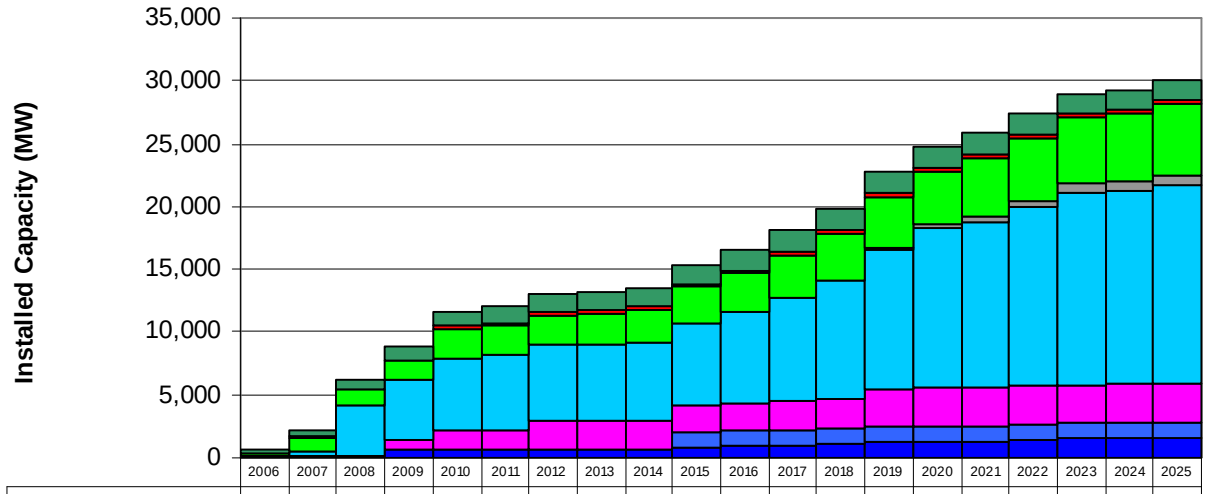
Source: OPA

Figure 2.8.9 – Portfolio 1B: Composition at 2025 (Installed)



Source: OPA

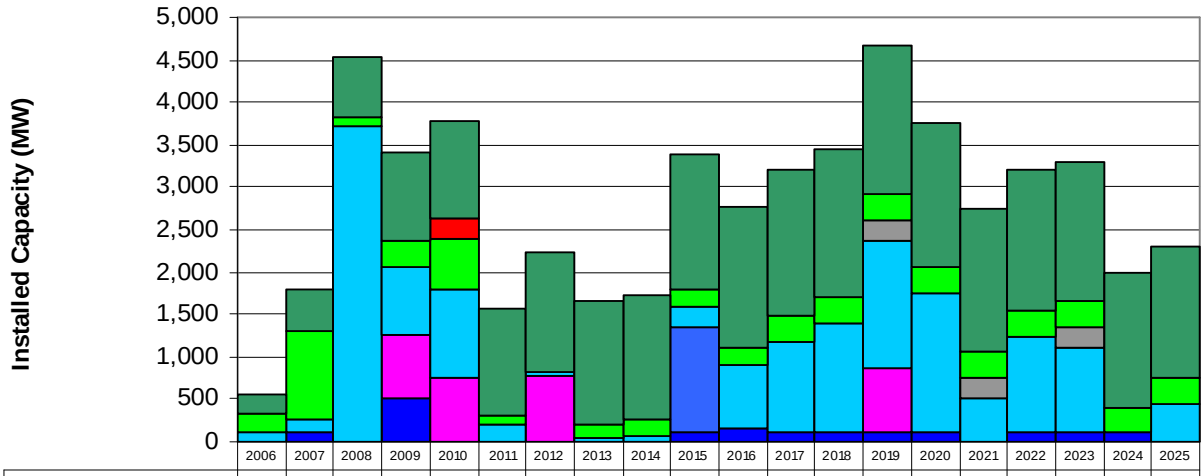
Table 2.8.6 – Portfolio 1B: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,700	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	250	250	500	500	750	750	750
Natural Gas & Oil	117	272	3,992	4,786	5,826	6,026	6,066	6,106	6,166	6,416	7,166	8,246	9,546	11,046	12,696	13,196	14,336	15,336	15,336	15,786
New and/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	2,270	2,270	2,270	2,270	3,040	3,040	3,040	3,040	3,040	3,040	3,040
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	121	121	629	629	629	629	629	629	729	879	979	1,079	1,179	1,279	1,279	1,379	1,479	1,579	1,579

Source: OPA

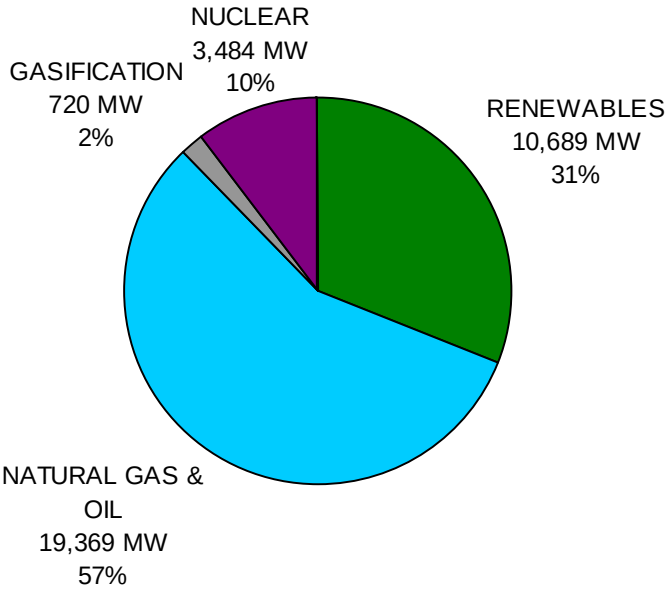
Table 2.8.7 – Portfolio 1B: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	150	200	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	250	0	250	0	250	0	0
Natural Gas & Oil	117	155	3,720	794	1,040	200	40	40	60	250	750	1,080	1,300	1,500	1,650	500	1,140	1,000	0	450
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	0	0	0	0	770	0	0	0	0	0	0
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	508	0	0	0	0	0	100	150	100	100	100	100	0	100	100	100	0

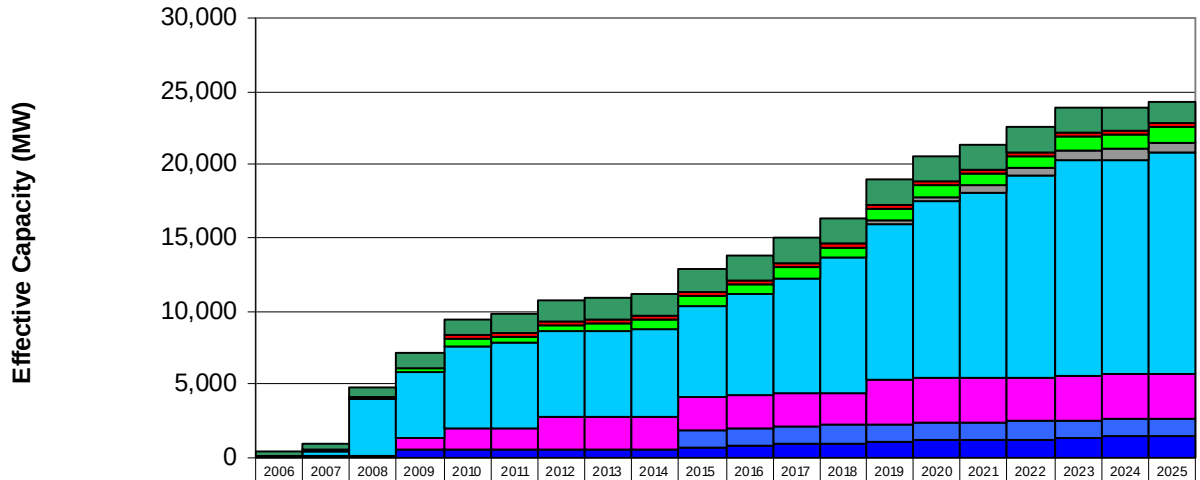
Source: OPA

Figure 2.8.10 – Portfolio 1B: Composition at 2025 (Effective)



Source: OPA

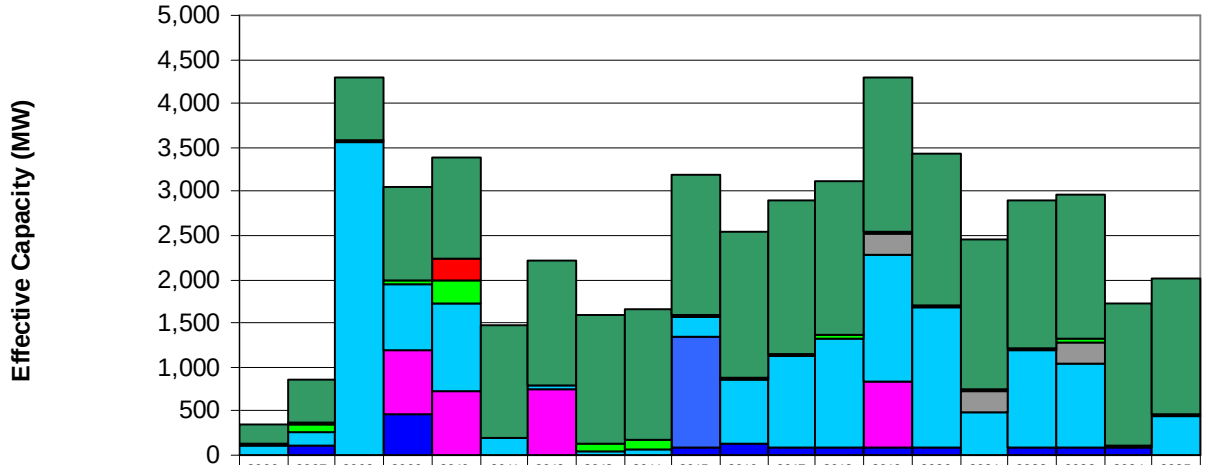
Table 2.8.8 – Portfolio 1B: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	668	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	240	240	480	480	720	720	720
Natural Gas & Oil	112	261	3,832	4,595	5,593	5,785	5,823	5,862	5,919	6,159	6,879	7,916	9,164	10,604	12,188	12,668	13,763	14,723	14,723	15,155
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	2,225	2,225	2,225	2,225	2,979	2,979	2,979	2,979	2,979	2,979	2,979
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	108	108	566	566	566	566	566	566	656	791	881	971	1,061	1,151	1,151	1,241	1,331	1,421	1,421

Source: OPA

Table 2.8.9 – Portfolio 1B: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	90	120	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	240	0	240	0	240	0	0
Natural Gas & Oil	112	149	3,571	762	998	192	38	38	58	240	720	1,037	1,248	1,440	1,584	480	1,094	960	0	432
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	0	0	0	0	755	0	0	0	0	0	0
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	0	90	135	90	90	90	90	0	90	90	90	0

Source: OPA

Table 2.8.10 – Portfolio 1B: Capacity at 2010, 2015, 2020, and 2025

1B Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	8,019	9,604	10,239	10,689
Natural Gas & Oil	9,808	10,374	16,403	19,369
Gasification	0	0	240	720
Nuclear	11,884	9,785	5,715	3,484
Coal	0	0	0	0
Total	31,262	31,837	34,886	36,361
1B Installed Capacity (MW)	**2010**	**2015**	**2020**	**2025**
CDM	1,551	2,073	2,288	2,098
Renewables	10,680	12,685	14,635	16,465
Natural Gas & Oil	10,802	11,392	17,672	20,762
Gasification	0	0	250	750
Nuclear	12,127	9,985	5,832	3,555
Coal	0	0	0	0
Total	35,161	36,136	40,678	43,631

Source: OPA

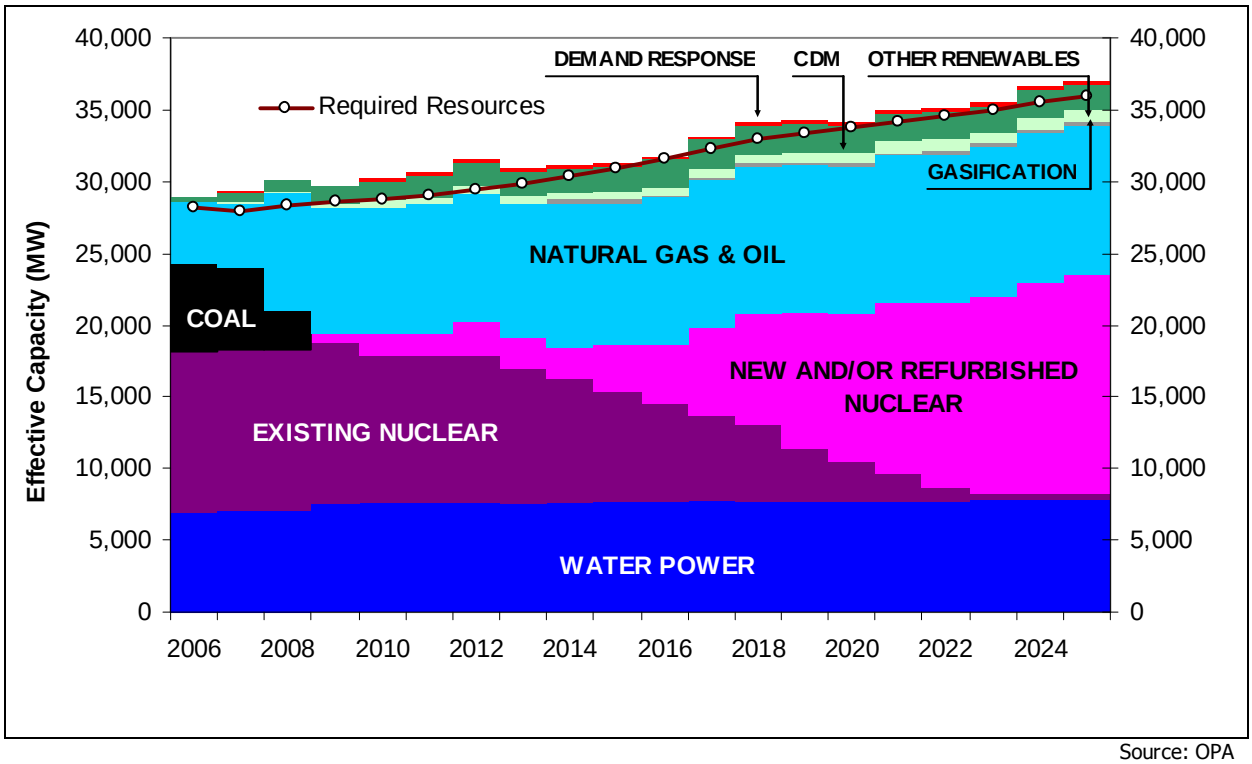
2.8.4.3. Scenario 2, Portfolio 2A

In this portfolio, most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering A, are refurbished or replaced as they reach the end of their estimated service lives. The entirety of Ontario's coal-fired fleet is removed from service and replaced by 2009.

Not all of the common elements outlined above are included. It is assumed the 1,250 MW of out-of-province firm purchases do not occur, 1,000 MW of natural gas-fired generation contemplated under government procurements does not materialize, and only half of the expected new hydroelectric, biomass, and fuel cell resources are placed in service. 1,300 MW of additional gas-fired generation is added towards the middle of the study period, as well as 3,000 MW of additional nuclear generation between 2017 and 2020.

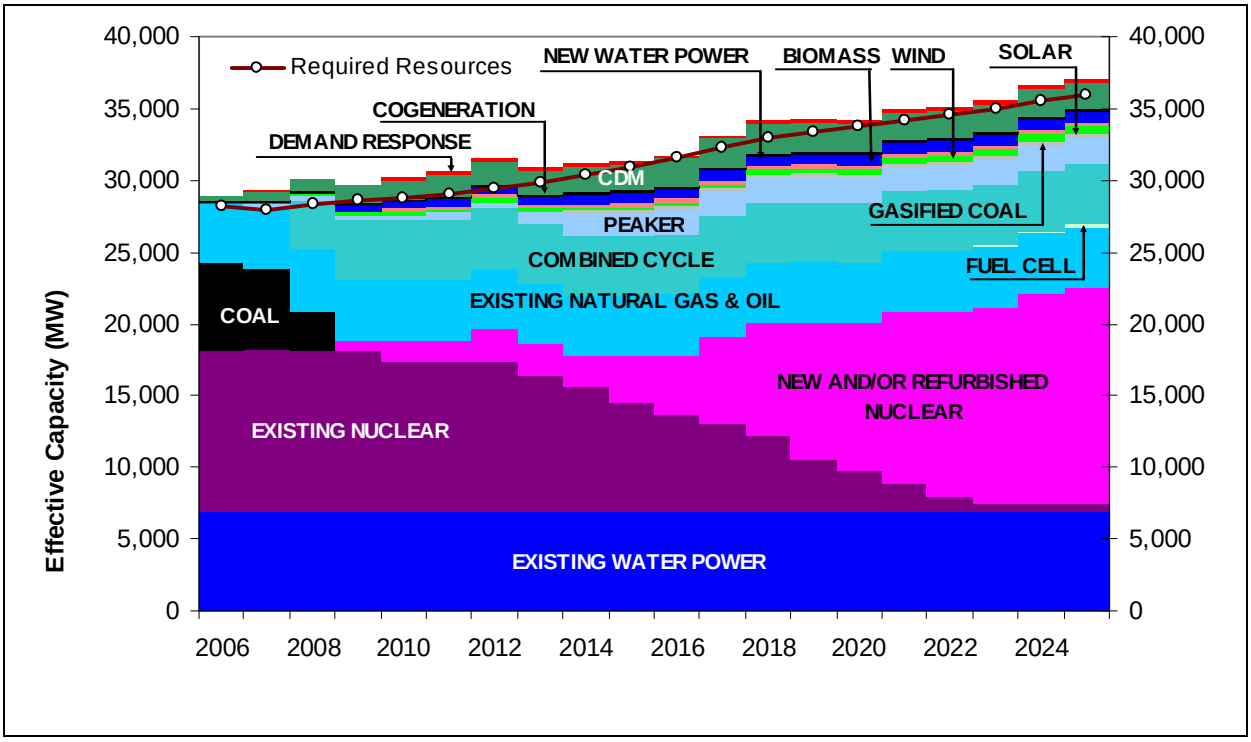
Figure 2.8.11 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.12. Energy production associated with the portfolio is shown in Figure 2.8.13. Figure 2.8.14 outlines the portfolio's composition at the year 2025. Tables 2.8.11 and 2.8.12 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.11 – Portfolio 2A



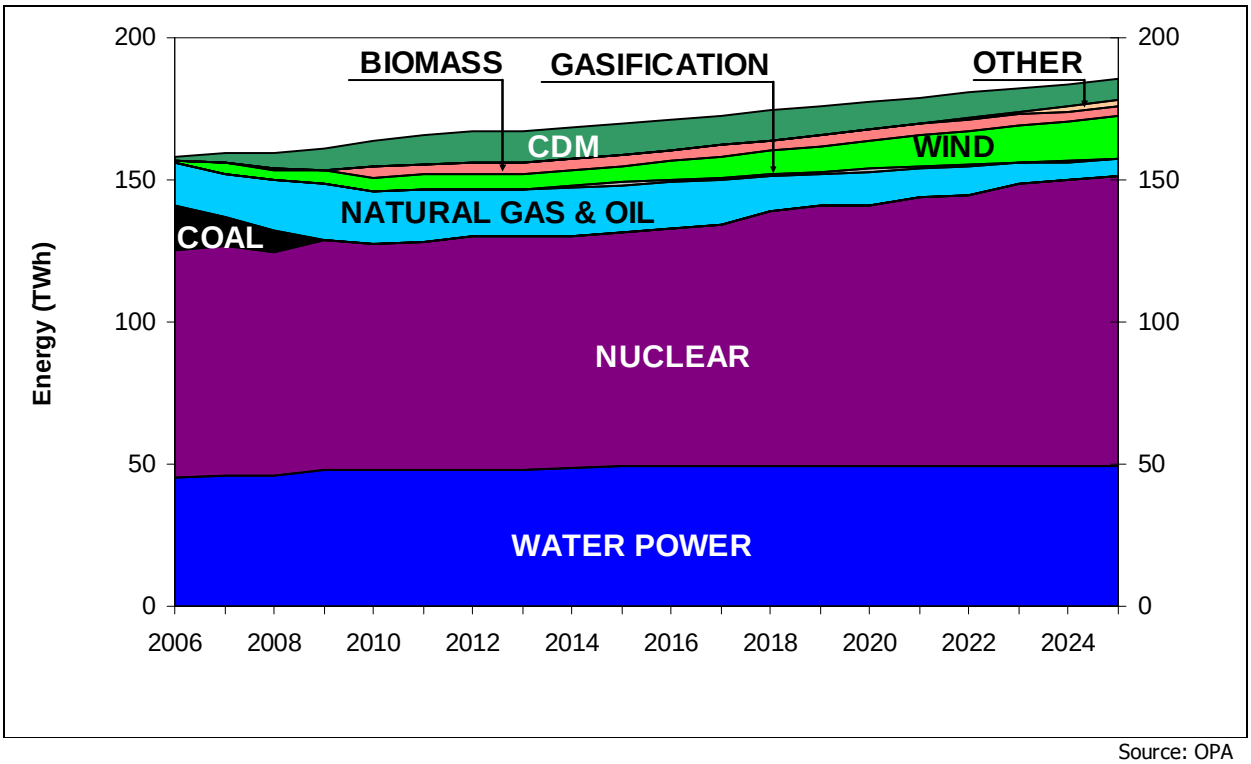
Source: OPA

Figure 2.8.12 – Portfolio 2A: Higher Resolution



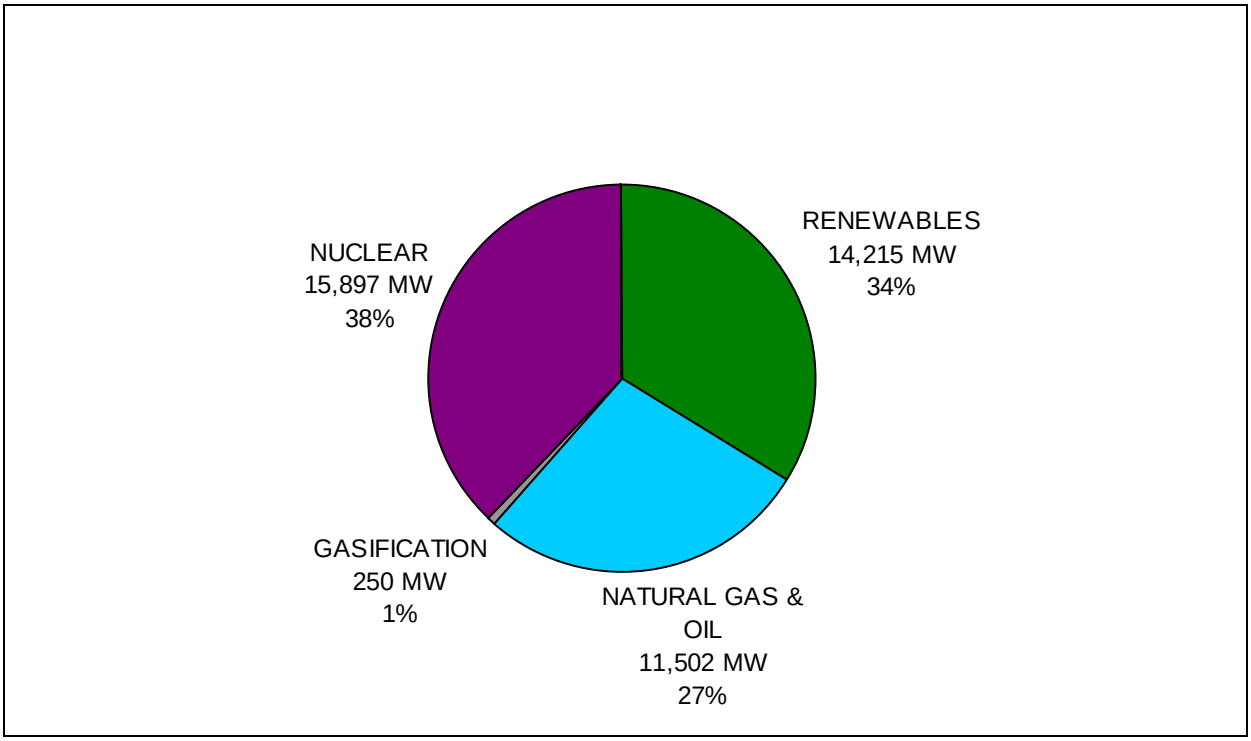
Source: OPA

Figure 2.8.13 – Portfolio 2A, Energy



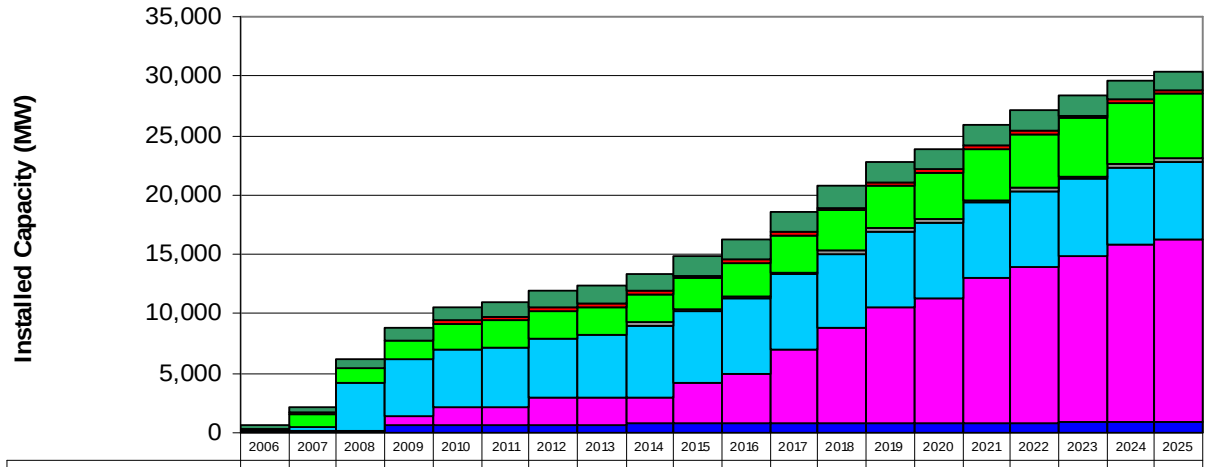
Source: OPA

Figure 2.8.14 – Portfolio 2A: Composition at 2025 (Installed)



Source: OPA

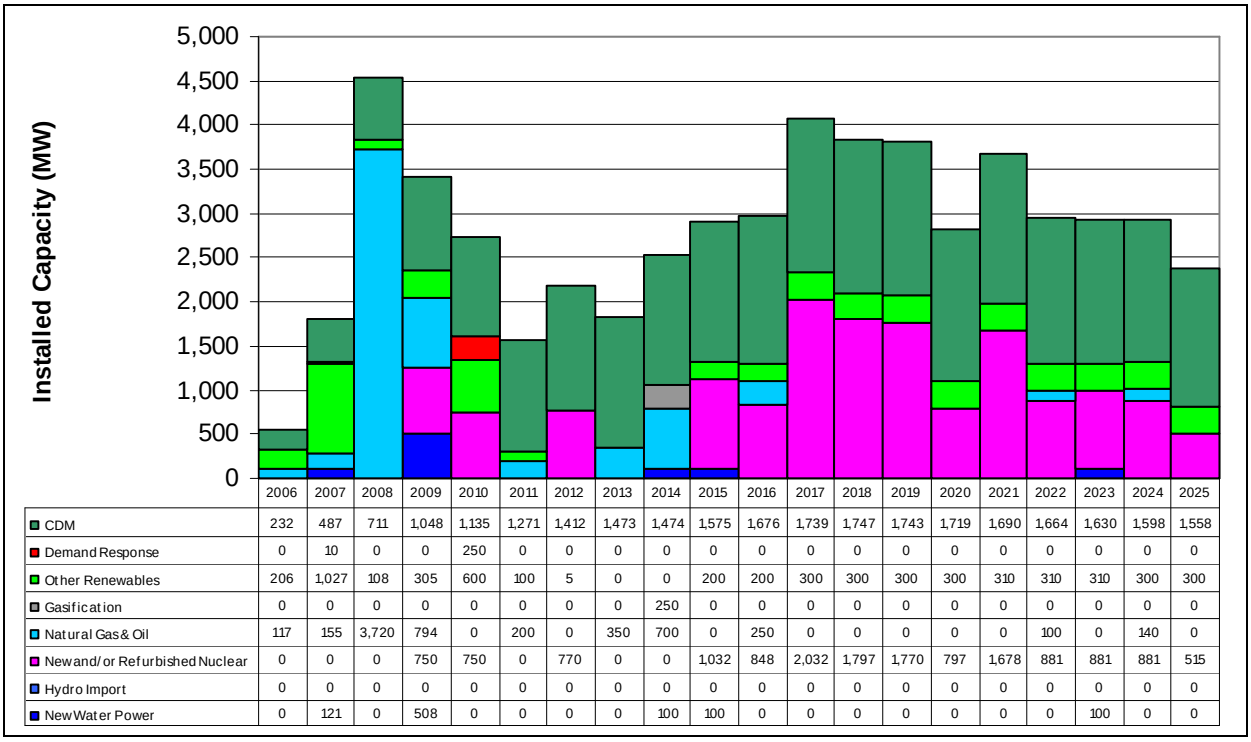
Table 2.8.11 – Portfolio 2A: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,350	2,350	2,550	2,750	3,050	3,350	3,650	3,950	4,260	4,570	4,880	5,180	5,480
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Natural Gas & Oil	117	272	3,992	4,786	4,786	4,986	4,986	5,336	6,036	6,036	6,286	6,286	6,286	6,286	6,286	6,286	6,386	6,386	6,526	6,526
New and/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	6,182	7,979	9,749	10,546	12,224	13,105	13,986	14,867	15,382
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	121	629	629	629	629	629	729	829	829	829	829	829	829	829	829	929	929	929

Source: OPA

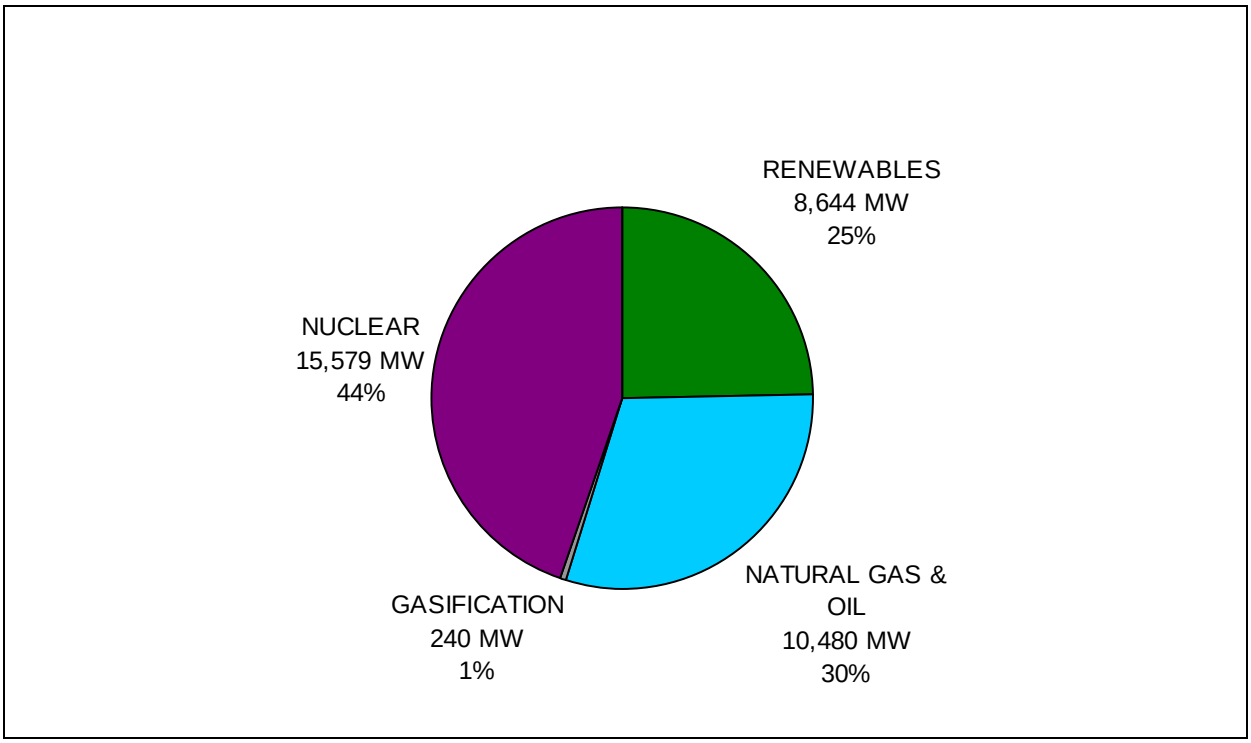
Table 2.8.12 – Portfolio 2A: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	0	0	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	250	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	117	155	3,720	794	0	200	0	350	700	0	250	0	0	0	0	0	100	0	140	0
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	2,032	1,797	1,770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	508	0	0	0	0	100	100	0	0	0	0	0	0	0	100	0	0

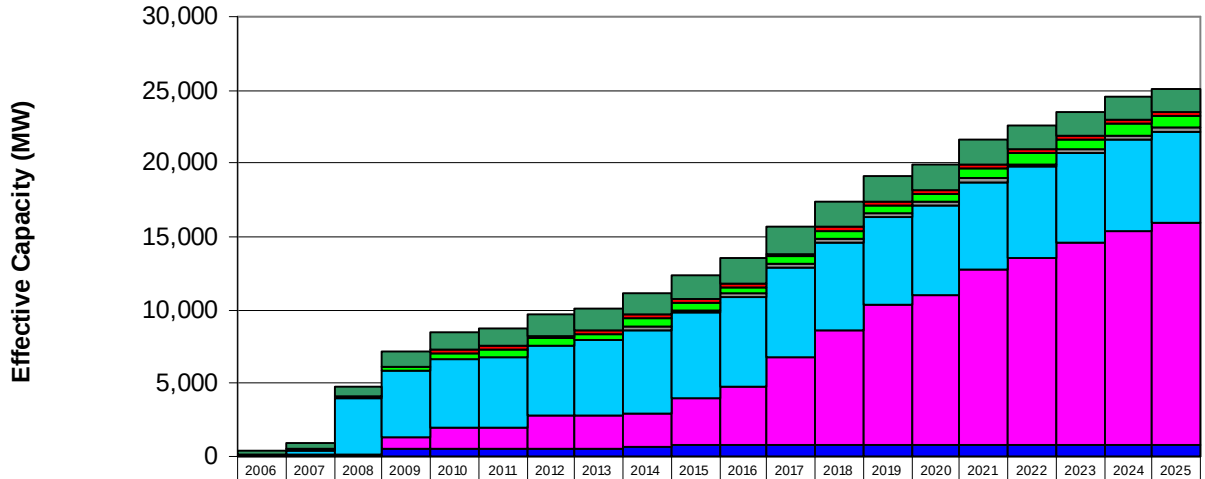
Source: OPA

Figure 2.8.15 – Portfolio 2A: Composition at 2025 (Effective)



Source: OPA

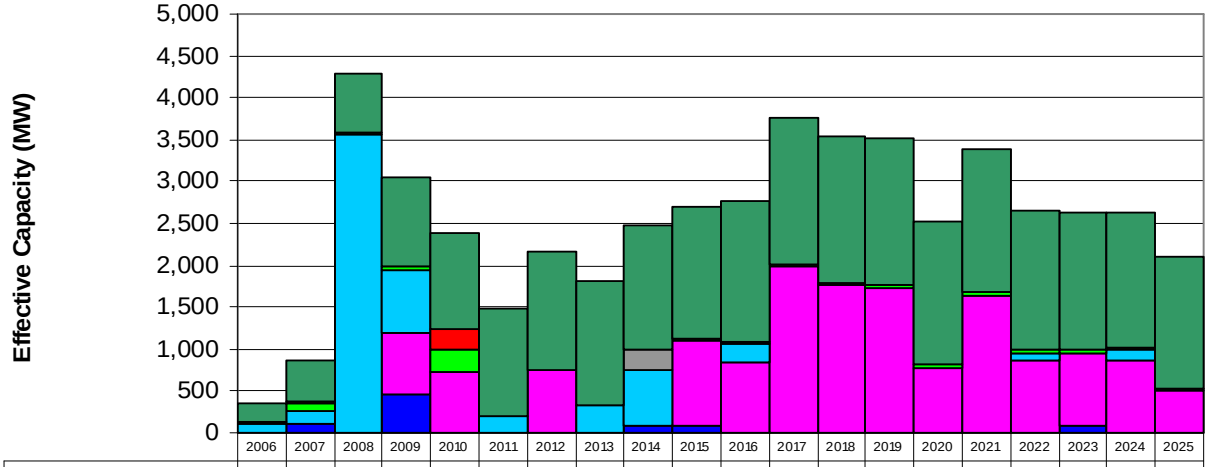
Table 2.8.13 – Portfolio 2A: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	458	458	478	498	528	558	588	618	658	698	738	768	798
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Natural Gas & Oil	112	261	3,832	4,595	4,595	4,787	4,787	5,123	5,795	5,795	6,035	6,035	6,035	6,035	6,035	6,035	6,131	6,131	6,265	6,265
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	6,058	7,819	9,554	10,335	11,980	12,843	13,706	14,570	15,074
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	108	566	566	566	566	566	656	746	746	746	746	746	746	746	746	836	836	836

Source: OPA

Table 2.8.14 – Portfolio 2A: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	0	0	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	3,571	762	0	192	0	336	672	0	240	0	0	0	0	0	96	0	134	0
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,991	1,761	1,735	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	90	90	0	0	0	0	0	0	0	90	0	0

Source: OPA

Table 2.8. 15 – Portfolio 2A: Capacity at 2010, 2015, 2020, and 2025

2A Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	8,019	8,234	8,374	8,644
Natural Gas & Oil	8,809	10,009	10,249	10,480
Gasification	0	240	240	240
Nuclear	11,884	10,797	13,071	15,579
Coal	0	0	0	0
Total	30,264	31,353	34,223	37,041
2A Installed Capacity (MW)	**2010**	**2015**	**2020**	**2025**
CDM	1,551	2,073	2,288	2,098
Renewables	10,680	11,185	12,585	14,215
Natural Gas & Oil	9,762	11,012	11,262	11,502
Gasification	0	250	250	250
Nuclear	12,127	11,017	13,338	15,897
Coal	0	0	0	0
Total	34,121	35,538	39,724	43,963

Source: OPA

2.8.4.4. Scenario 2, Portfolio 2B

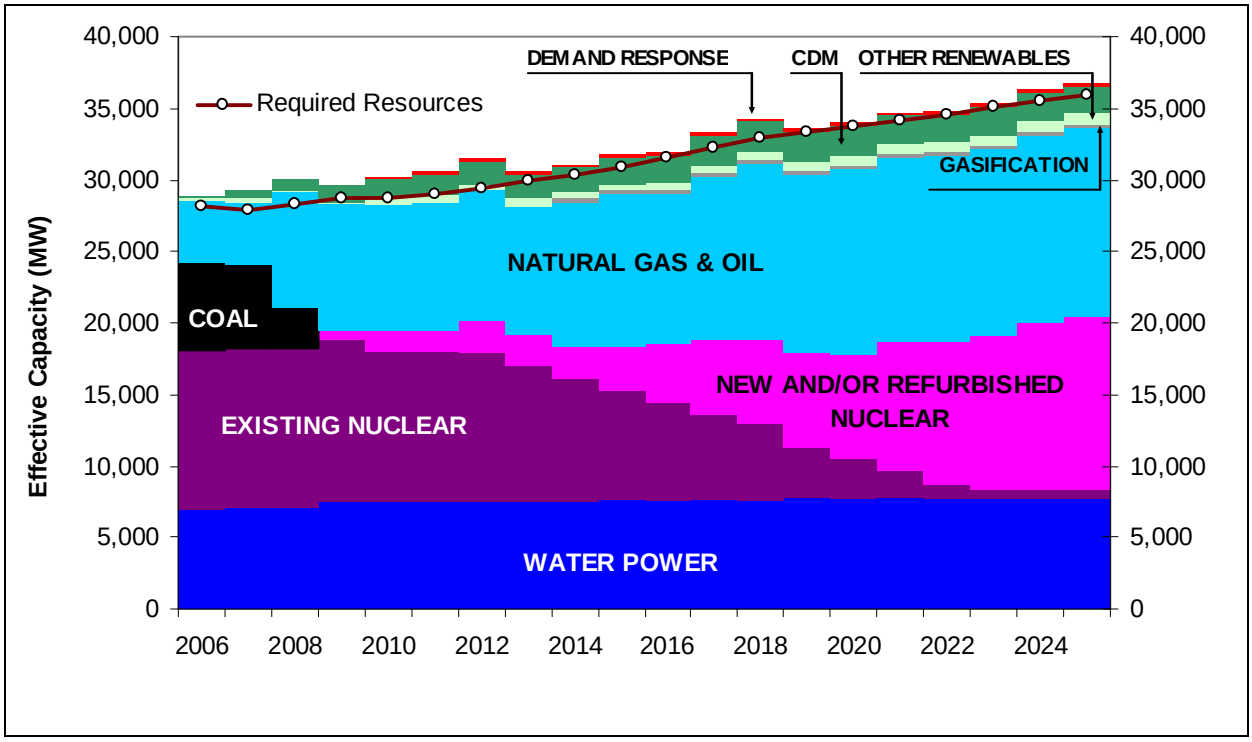
This portfolio is similar to Portfolio 2A in that not all of the common elements outlined in section 2.8.4 are assumed to enter service. As in Portfolio 2A, Portfolio 2B assumes the 1,200 MW of out-of-province firm purchases do not occur, 1,000 MW of natural gas-fired generation contemplated under government procurements does not materialize, and only half of the new hydroelectric, biomass, and fuel cell resources are placed in service.

Similarly, Portfolio 2B sees the refurbishment or replacement of most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering A. The entirety of Ontario's coal-fired fleet is removed from service and replaced by 2009.

Unlike Portfolio 2A, which added 3,000 MW of new nuclear generation, Portfolio 2B does not add any new nuclear generation. Instead, Portfolio 2B adds 3,100 MW of new gas-fired generation towards the middle and later part of the study period.

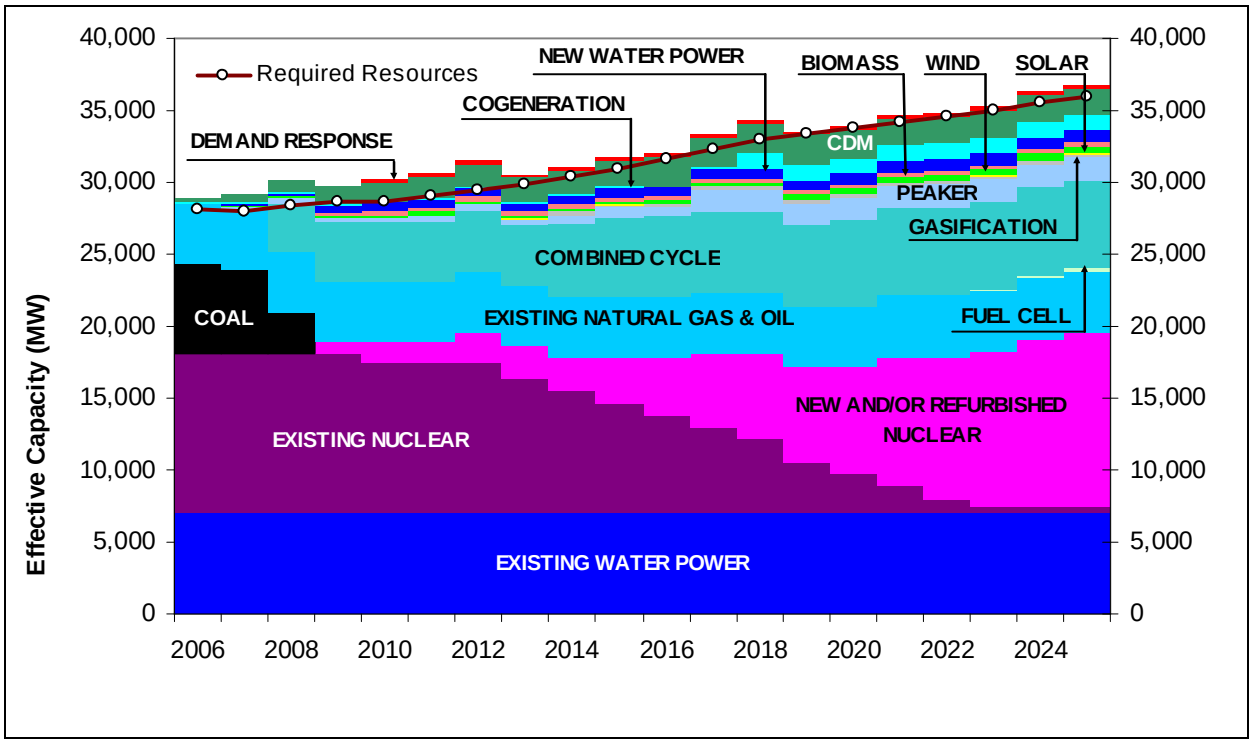
Figure 2.8.16 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.17. Energy production associated with the portfolio is shown in Figure 2.8.18. Figure 2.8.19 outlines the portfolio's composition at the year 2025. Tables 2.8.16 and 2.8.17 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.16 – Portfolio 2B



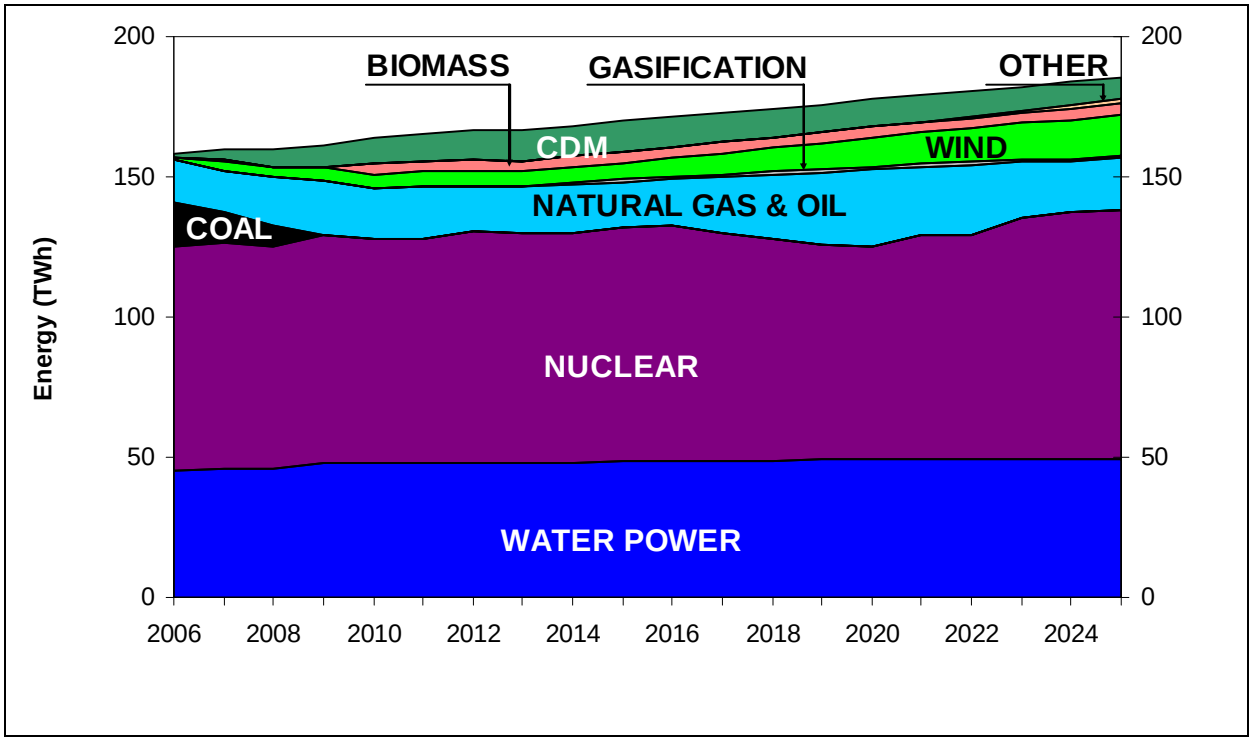
Source: OPA

Figure 2.8.17 – Portfolio 2B: Higher Resolution



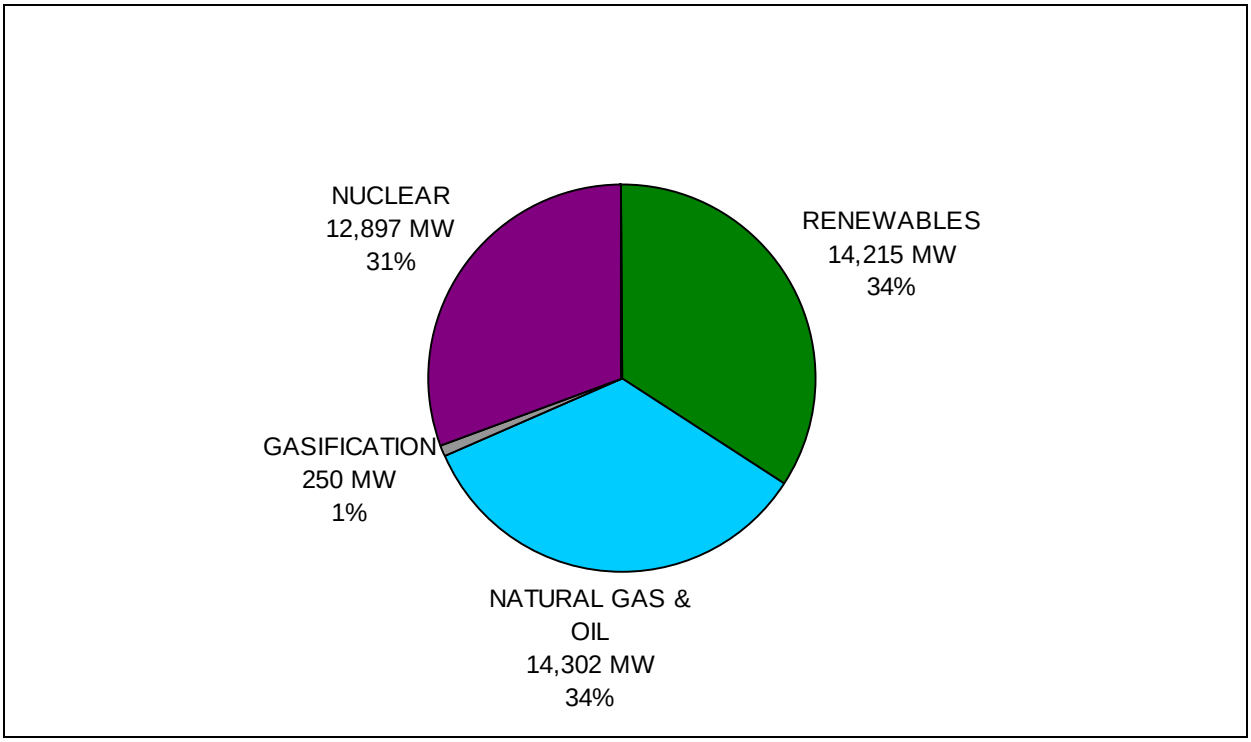
Source: OPA

Figure 2.8.18 – Portfolio 2B, Energy



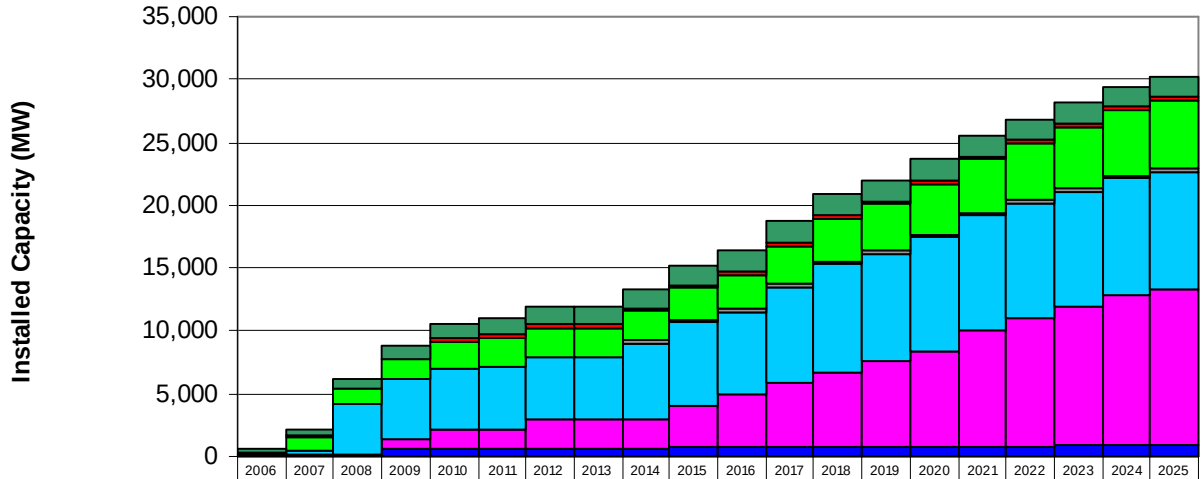
Source: OPA

Figure 2.8.19 – Portfolio 2B: Composition at 2025 (Installed)



Source: OPA

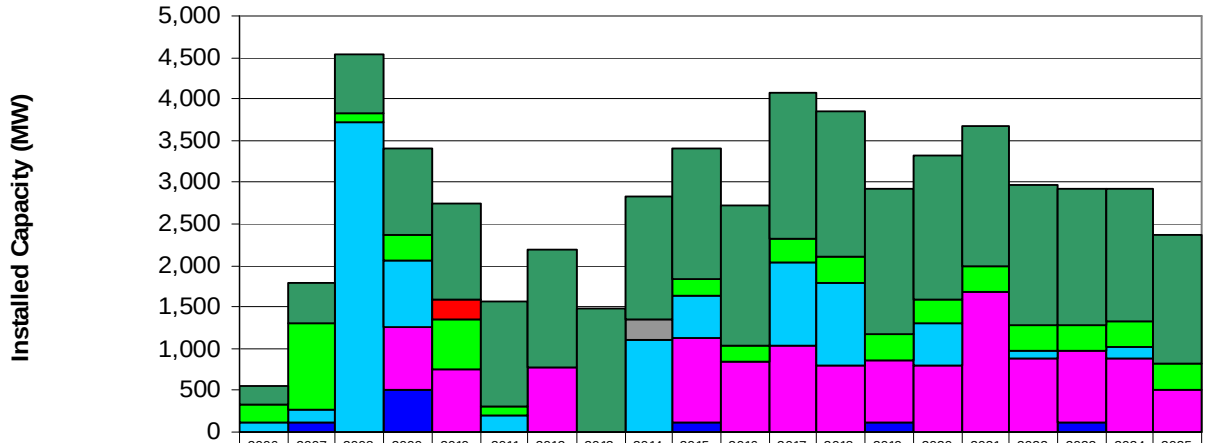
Table 2.8.16 – Portfolio 2B: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,350	2,350	2,550	2,750	3,050	3,350	3,650	3,950	4,260	4,570	4,880	5,180	5,480
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Natural Gas& Oil	117	272	3,992	4,786	4,786	4,986	4,986	4,986	6,086	6,586	6,586	7,586	8,586	8,586	9,086	9,086	9,186	9,186	9,326	9,326
Newand/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	5,979	6,749	7,546	9,224	10,105	10,986	11,867	12,382
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NewWater Power	0	121	121	629	629	629	629	629	629	729	729	729	729	829	829	829	829	929	929	929

Source: OPA

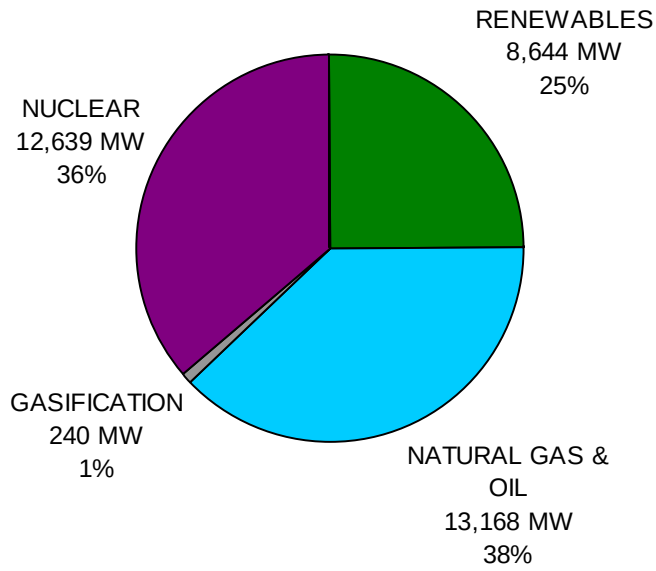
Table 2.8.17: Portfolio 2B: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	0	0	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	250	0	0	0	0	0	0	0	0	0	0	0
Natural Gas& Oil	117	155	3,720	794	0	200	0	0	1,100	500	0	1,000	1,000	0	500	0	100	0	140	0
Newand/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	797	770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NewWater Power	0	121	0	508	0	0	0	0	0	100	0	0	0	100	0	0	0	100	0	0

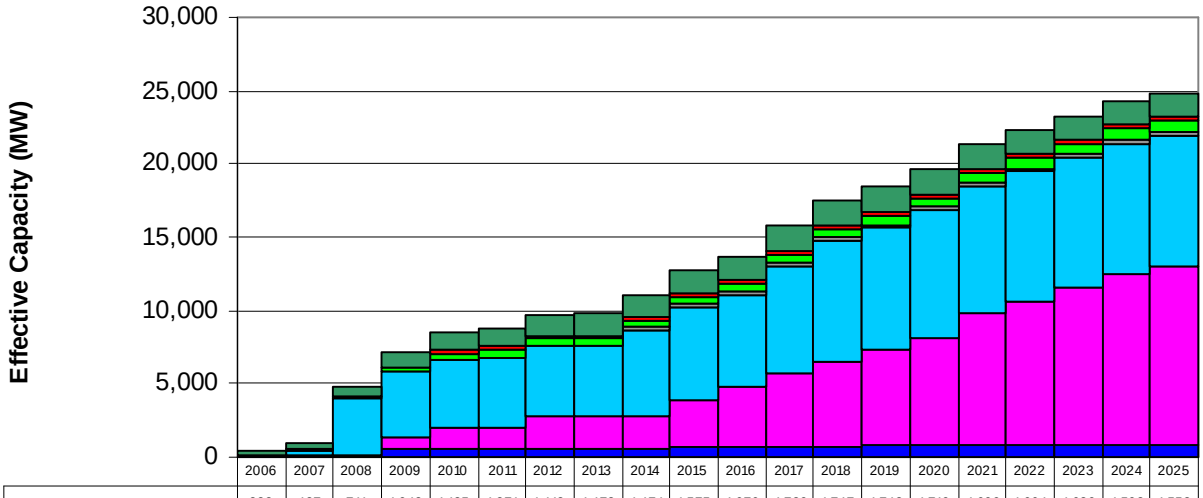
Source: OPA

Figure 2.8.20 – Portfolio 2B: Composition at 2025 (Effective)



Source: OPA

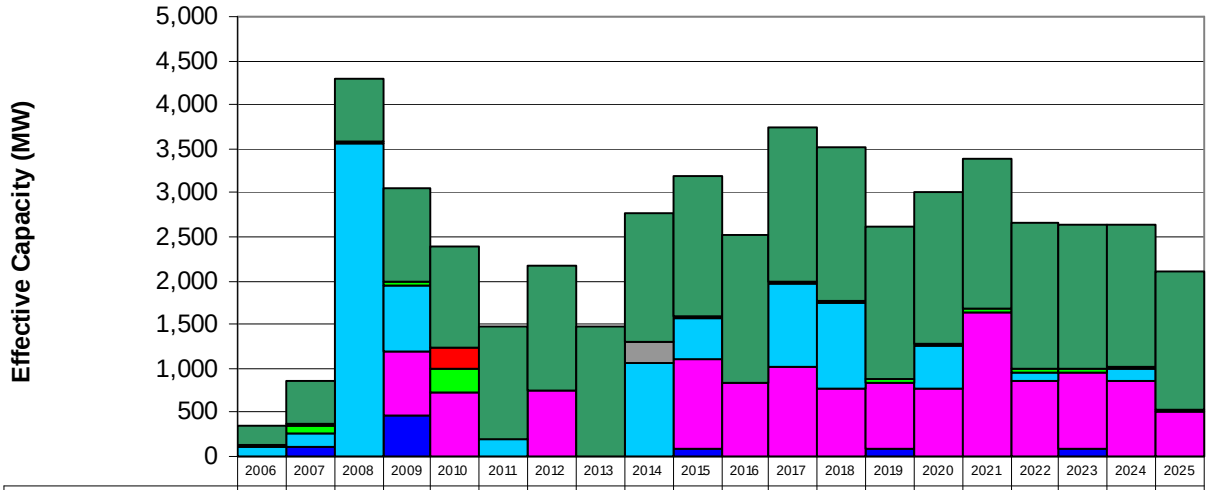
Table 2.8.18 – Portfolio 2B: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	458	458	478	498	528	558	588	618	658	698	738	768	798
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Natural Gas& Oil	112	261	3,832	4,595	4,595	4,787	4,787	4,787	5,843	6,323	6,323	7,283	8,243	8,243	8,723	8,723	8,819	8,819	8,953	8,953
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	5,859	6,614	7,395	9,040	9,903	10,766	11,630	12,134
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	108	566	566	566	566	566	566	656	656	656	656	746	746	746	746	836	836	836

Source: OPA

Table 2.8.19 – Portfolio 2B: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	0	0	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	3,571	762	0	192	0	0	1,056	480	0	960	960	0	480	0	96	0	134	0
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	781	755	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	0	90	0	0	0	90	0	0	0	90	0	0

Source: OPA

Table 2.8.20 – Portfolio 2B: Capacity at 2010, 2015, 2020, and 2025

2B Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	8,019	8,144	8,374	8,644
Natural Gas & Oil	8,809	10,537	12,937	13,168
Gasification	0	240	240	240
Nuclear	11,884	10,797	10,131	12,639
Coal	0	0	0	0
Total	30,264	31,791	33,971	36,789

2B Installed Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	10,680	11,085	12,585	14,215
Natural Gas & Oil	9,762	11,562	14,062	14,302
Gasification	0	250	250	250
Nuclear	12,127	11,017	10,338	12,897
Coal	0	0	0	0
Total	34,121	35,988	39,524	43,763

Source: OPA

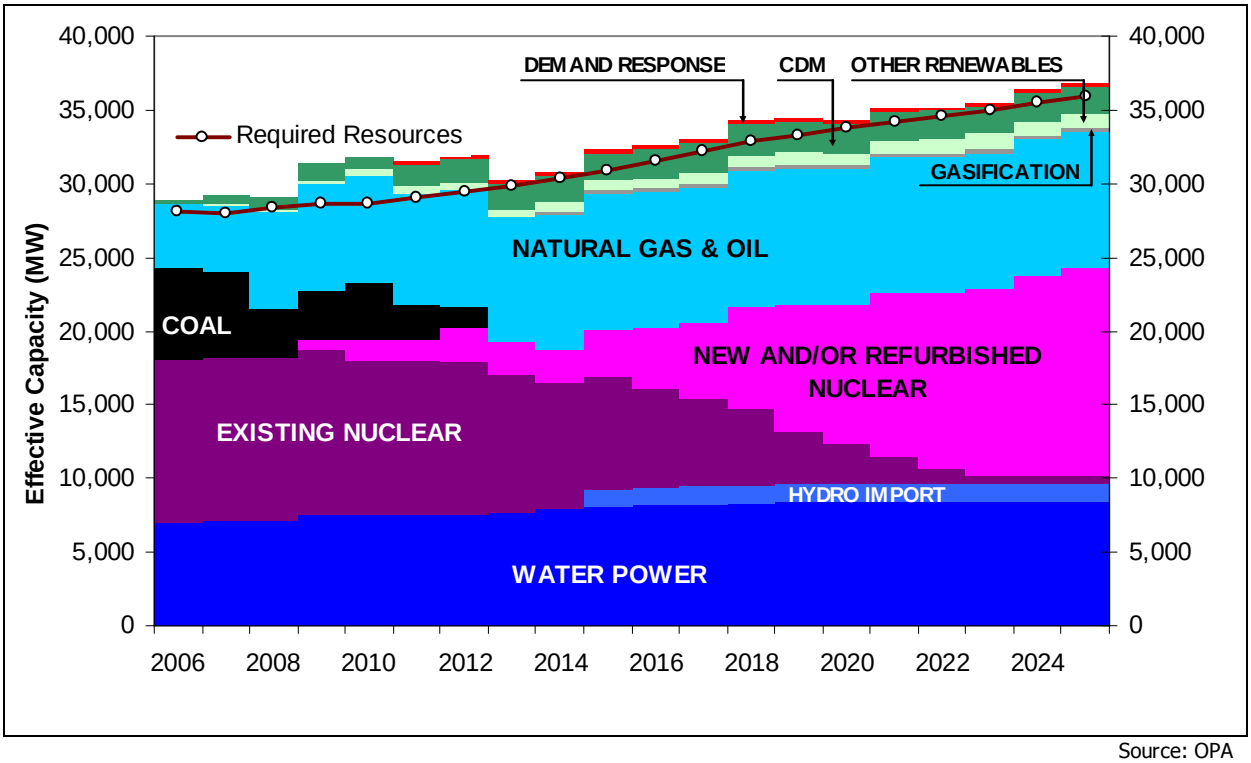
2.8.4.5. Scenario 3, Portfolio 3A

portfolio, the phase-out of some of Ontario's coal-fired units is unavoidably delayed until the end of 2012. The rest of Ontario's coal-fired fleet is removed from service and replaced by 2009. Because this portfolio assumes this delay has been anticipated and planned for, approximately 2,000 MW of natural gas-fired procurements are not placed in service, while approximately 600 MW of natural gas-fired procurements are deferred by several years until 2012 to 2014. Additional emission controls are added to two coal-fired units.

Most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering A, are refurbished or replaced as they reach the end of their estimated service lives. 2,000 MW of additional nuclear generation is added in 2018 and 2019. All common elements as described in section 2.8.4, with the exception of the 2,000 MW of gas-fired procurements mentioned in the above paragraph, are assumed to enter service. Approximately 750 MW of additional natural gas-fired generation is added throughout the study period.

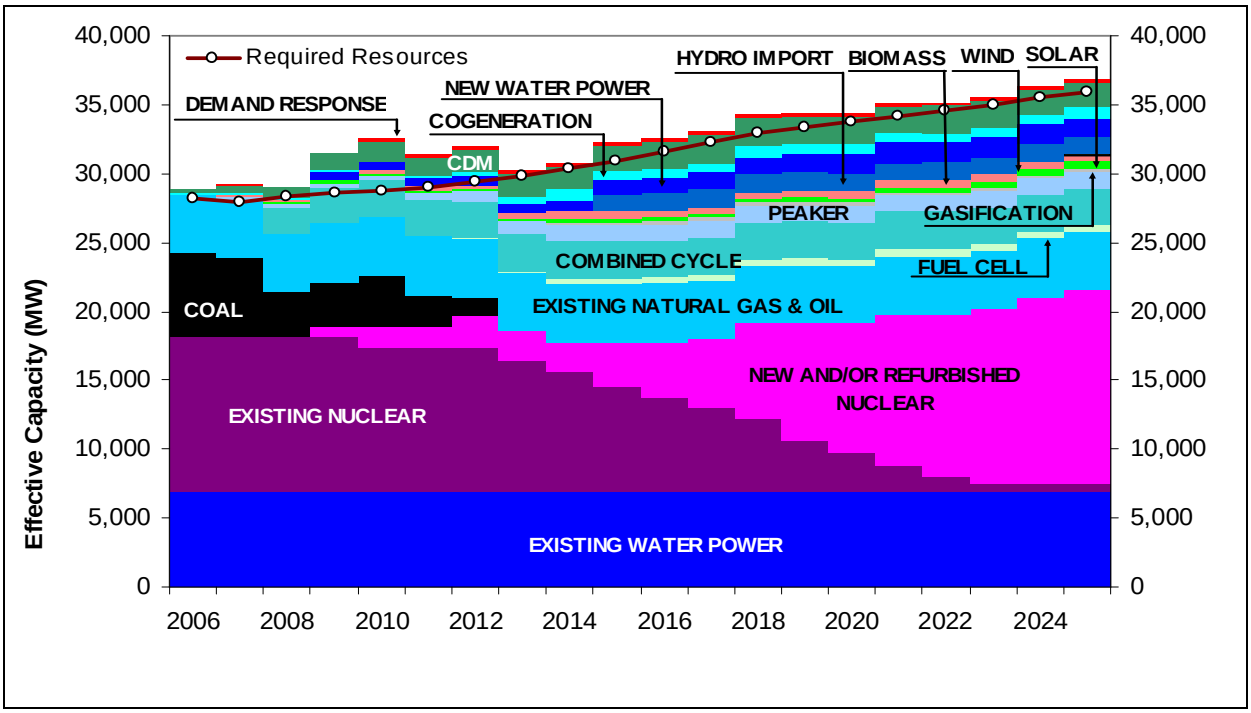
Figure 2.8.21 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.22. Energy production associated with the portfolio is shown in Figure 2.8.23. Figure 2.8.24 outlines the portfolio's composition at the year 2025. Tables 2.8.21 and 2.8.22 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.21 – Portfolio 3A



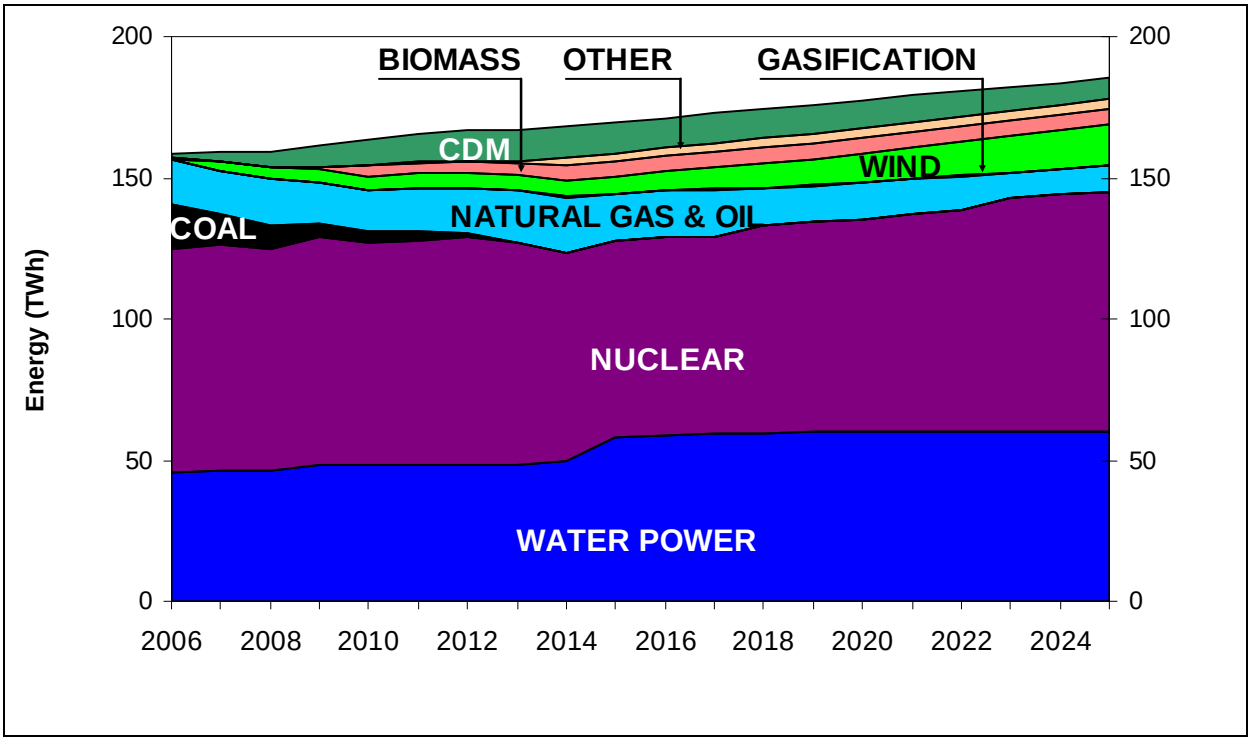
Source: OPA

Figure 2.8.22 – Portfolio 3A: Higher Resolution



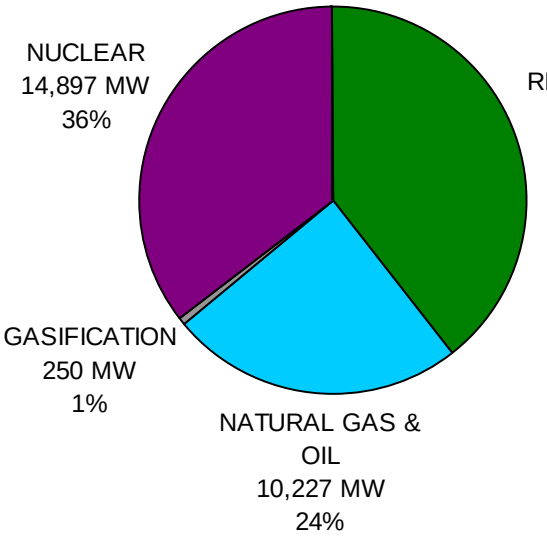
Source: OPA

Figure 2.8.23 – Portfolio 3A, Energy



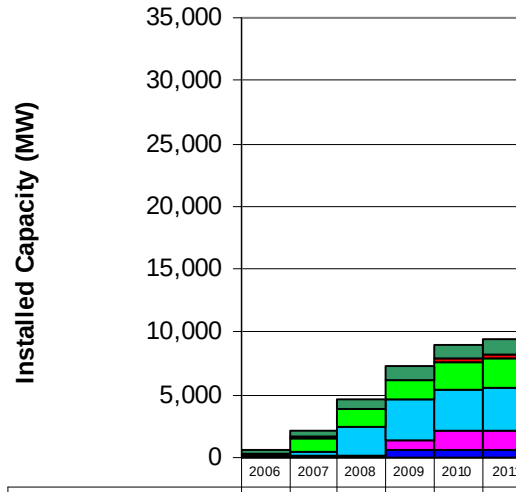
Source: OPA

Figure 2.8.24 – Portfolio 3A: Composition at 2025 (Installed)



Source: OPA

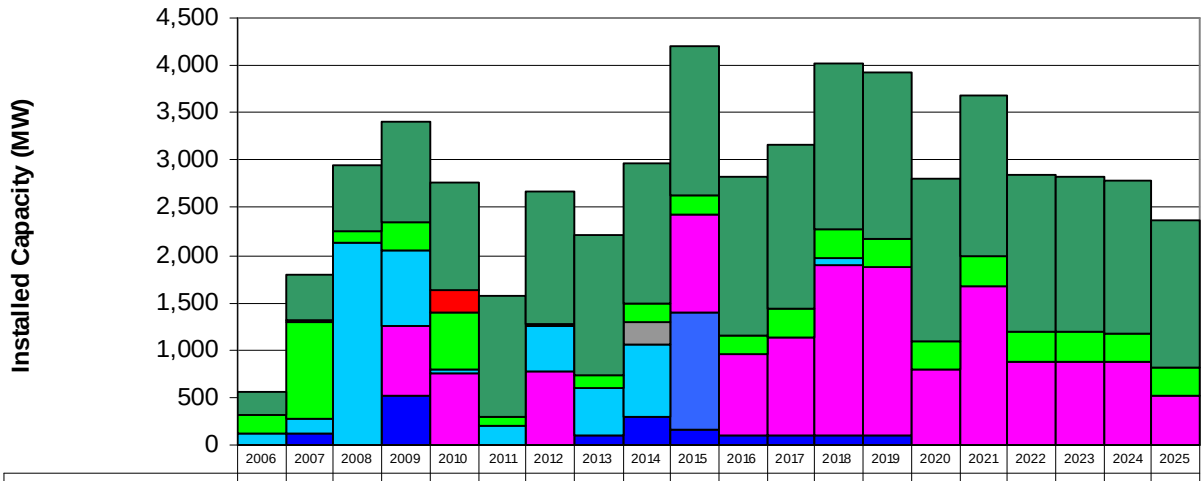
Table 2.8.21 – Portfolio 3A: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,700	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Natural Gas& Oil	117	272	2,407	3,201	3,241	3,441	3,931	4,421	5,171	5,171	5,171	5,171	5,251	5,251	5,251	5,251	5,251	5,251	5,251	5,251
Newand/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	6,979	8,749	9,546	11,224	12,105	12,986	13,867	14,382
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
NewWater Power	0	121	121	629	629	629	629	729	1,029	1,179	1,279	1,379	1,479	1,579	1,579	1,579	1,579	1,579	1,579	1,579

Source: OPA

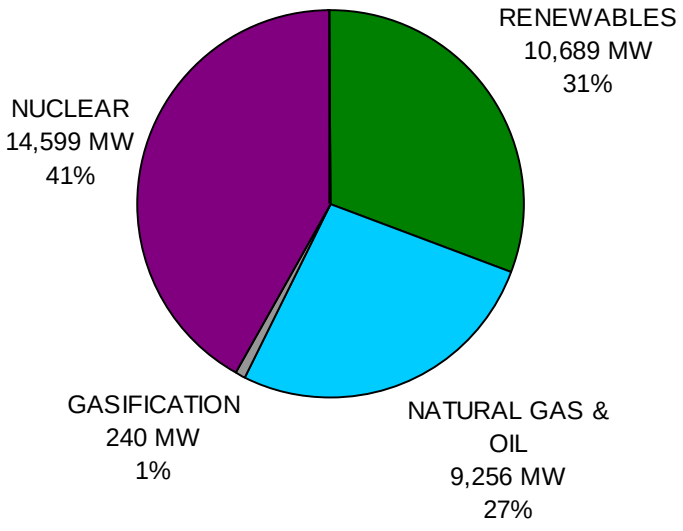
Table 2.8.22 – Portfolio 3A: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	150	200	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	250	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	117	155	2,135	794	40	200	490	490	750	0	0	0	80	0	0	0	0	0	0	0
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	1,797	1,770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	508	0	0	0	100	300	150	100	100	100	100	0	0	0	0	0	0

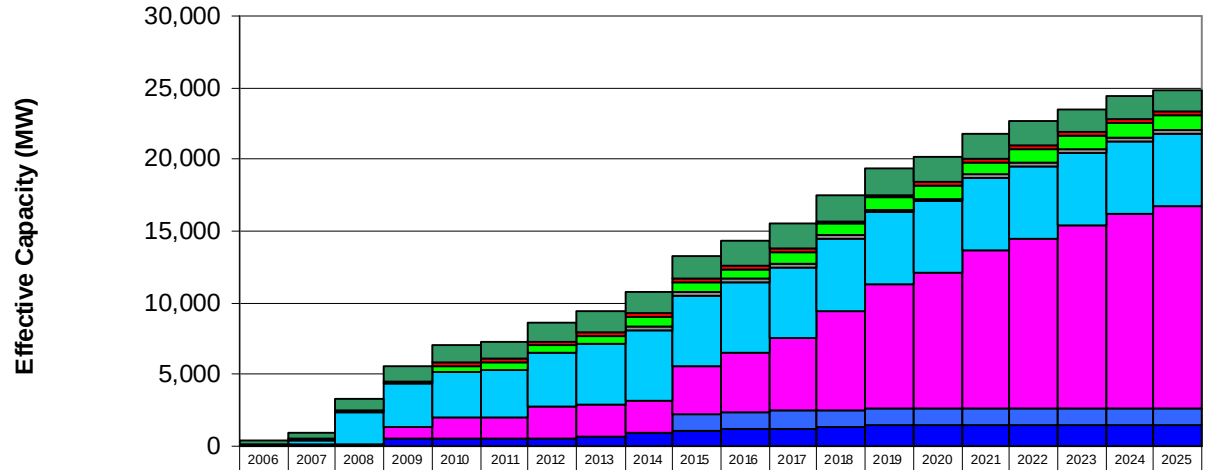
Source: OPA

Figure 2.8.25 – Portfolio 3A: Composition at 2025 (Effective)



Source: OPA

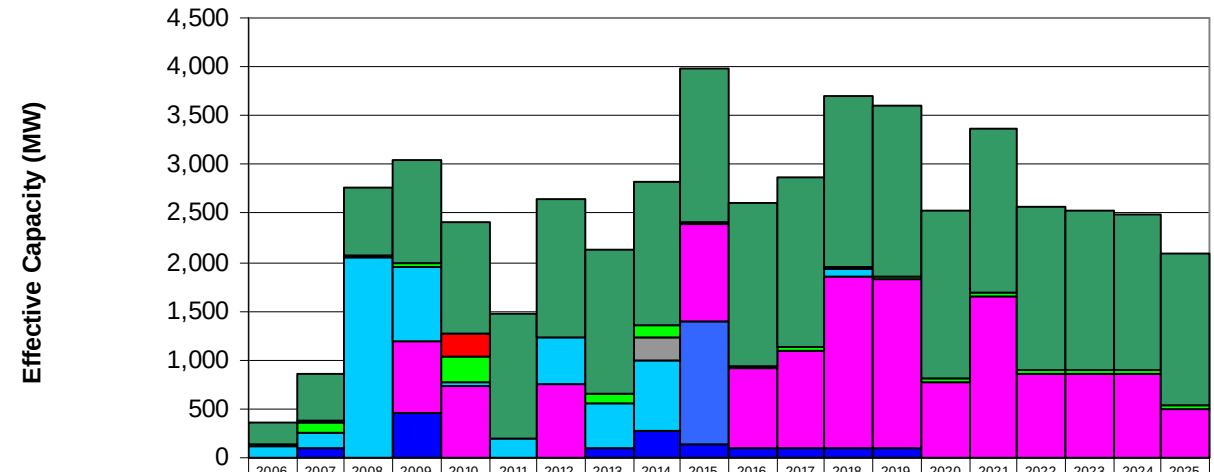
Table 2.8.23 – Portfolio 3A: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	668	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Natural Gas & Oil	112	261	2,311	3,073	3,111	3,303	3,774	4,244	4,964	4,964	4,964	4,964	5,041	5,041	5,041	5,041	5,041	5,041	5,041	5,041
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	6,839	8,574	9,355	11,000	11,863	12,726	13,590	14,094
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	108	108	566	566	566	566	656	926	1,061	1,151	1,241	1,331	1,421	1,421	1,421	1,421	1,421	1,421	1,421

Source: OPA

Table 2.8.24 – Portfolio 3A: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	90	120	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	2,050	762	38	192	470	470	720	0	0	0	77	0	0	0	0	0	0	0
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	1,761	1,735	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	90	270	135	90	90	90	90	0	0	0	0	0	0

Source: OPA

Table 2.8.25 – Portfolio 3A: Capacity at 2010, 2015, 2020, and 2025

3A Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	8,019	10,009	10,509	10,689
Natural Gas & Oil	7,326	9,179	9,256	9,256
Gasification	0	240	240	240
Nuclear	11,884	10,797	12,091	14,599
Coal	3,748	0	0	0
Total	32,529	32,298	34,384	36,882
3A Installed Capacity (MW)	**2010**	**2015**	**2020**	**2025**
CDM	1,551	2,073	2,288	2,098
Renewables	10,680	13,135	14,935	16,465
Natural Gas & Oil	8,217	10,147	10,227	10,227
Gasification	0	250	250	250
Nuclear	12,127	11,017	12,338	14,897
Coal	3,945	0	0	0
Total	36,521	36,623	40,039	43,938

Source: OPA

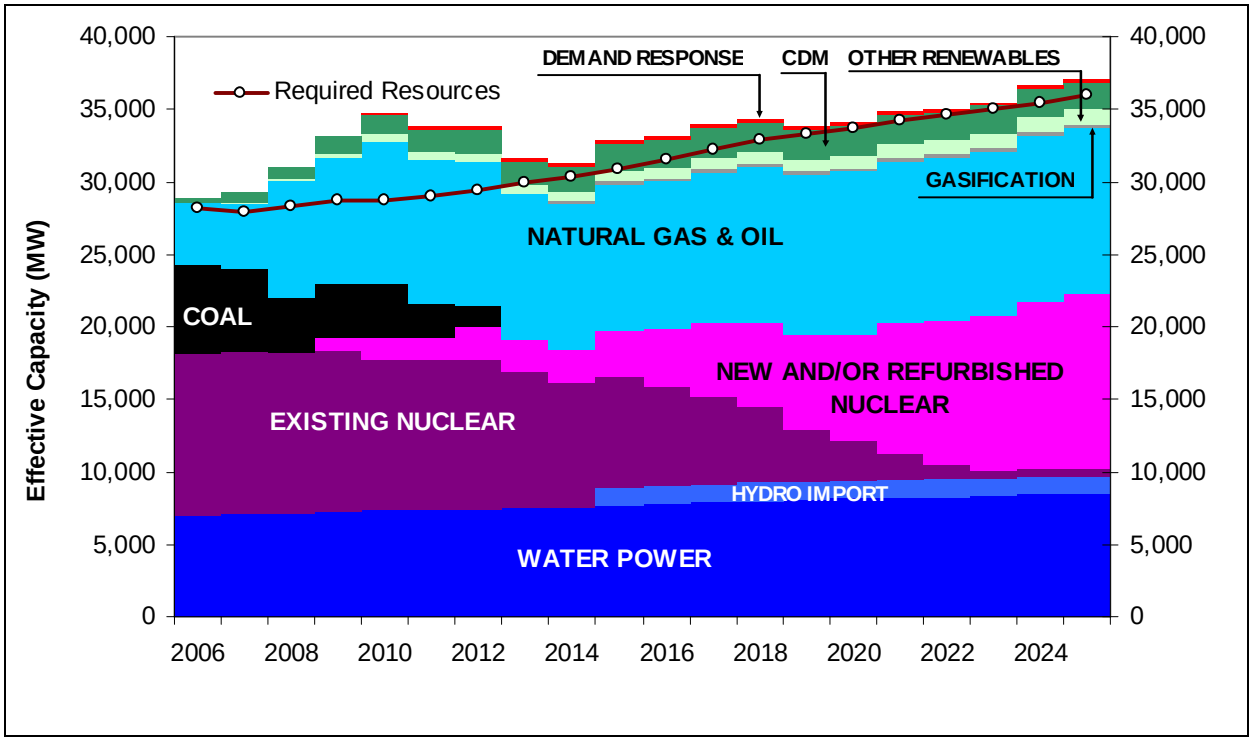
2.8.4.6. Scenario 3, Portfolio 3B

This portfolio is similar to Portfolio 3A in that the full replacement of some of the coal-fired units is unavoidably delayed until the end of 2012, while the rest of Ontario's coal-fired fleet is retired and replaced by 2009. Unlike in Portfolio 3A, Portfolio 3B assumes this delay has not been anticipated and therefore not planned for. It therefore sees all natural gas-fired procurements installed as contemplated under government procurements. No additional emission controls are added in this portfolio. Further, Portfolio 3B does not see the addition of any additional nuclear generation.

In Portfolio 3B, most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering A, are refurbished or replaced as they reach the end of their estimated service lives. All of the common elements outlined in section 2.8.4 are added. Approximately 1,000 MW of additional natural gas-fired generation is added throughout the study period.

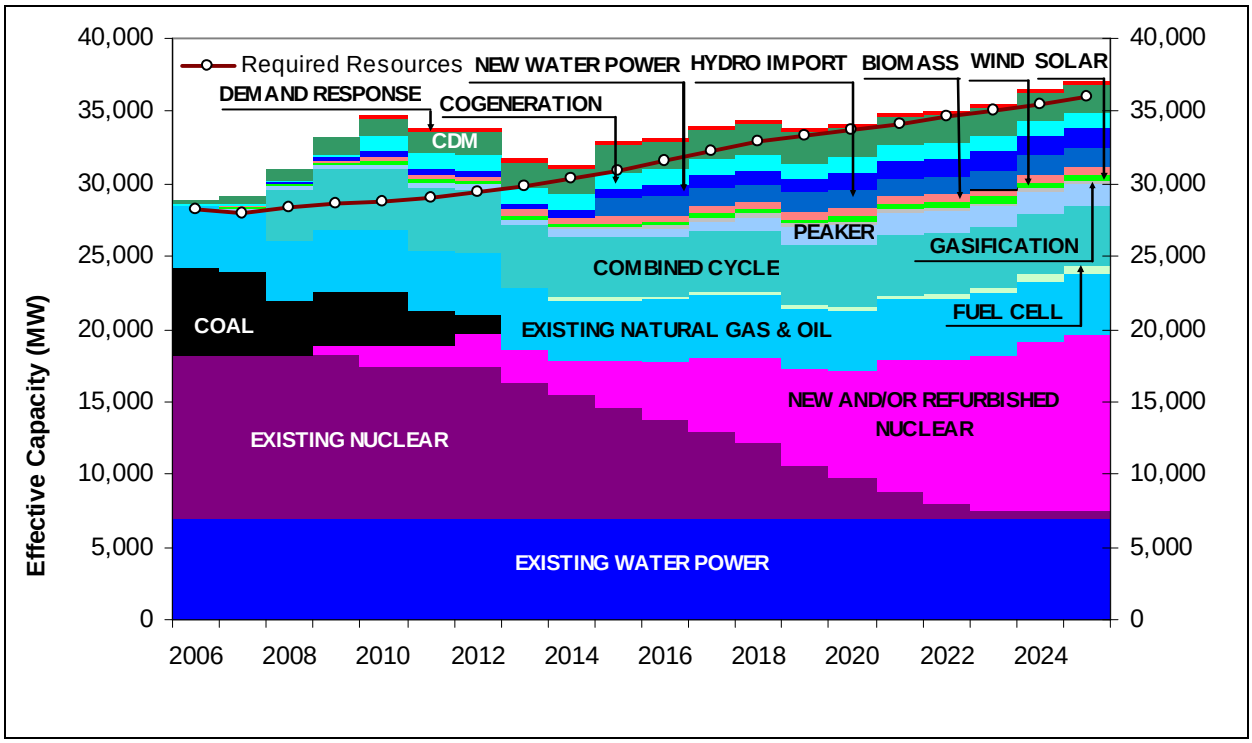
Figure 2.8.26 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.27. Energy production associated with the portfolio is shown in Figure 2.8.28. Figure 2.8.29 outlines the portfolio's composition at the year 2025. Tables 2.8.26 and 2.8.27 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.26 – Portfolio 3B



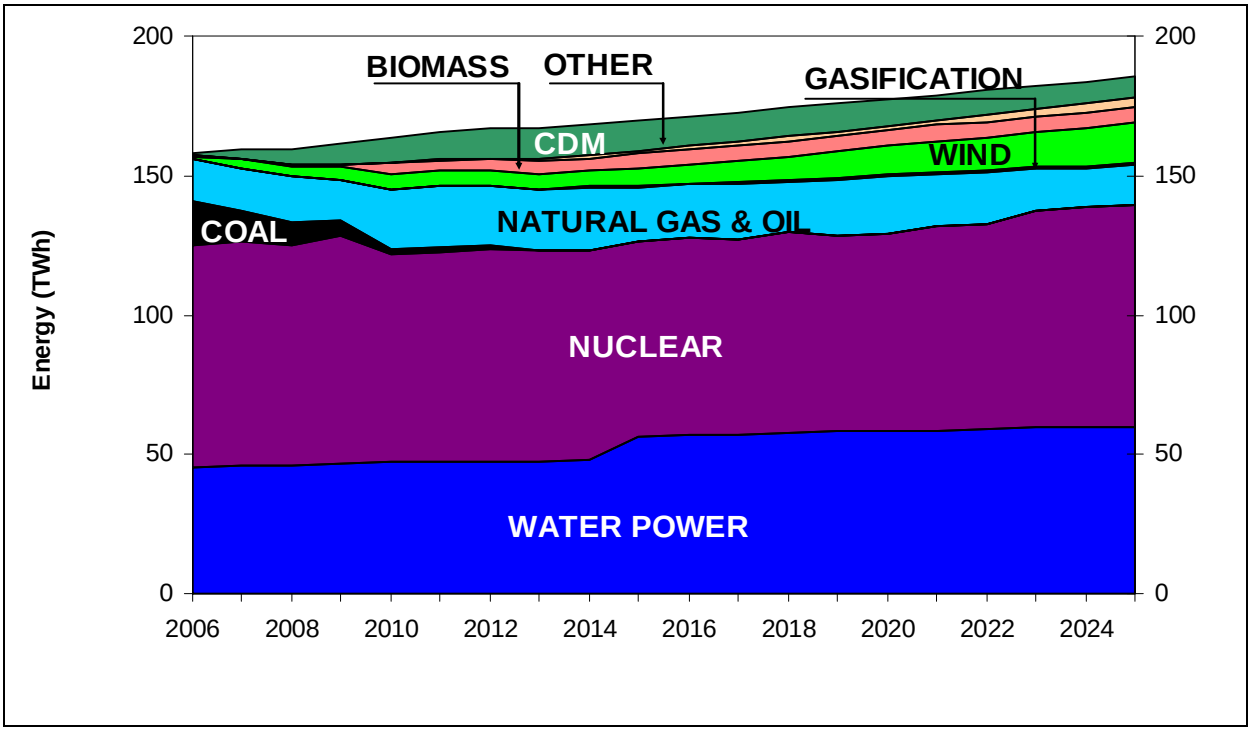
Source: OPA

Figure 2.8.27 – Portfolio 3B: Higher Resolution



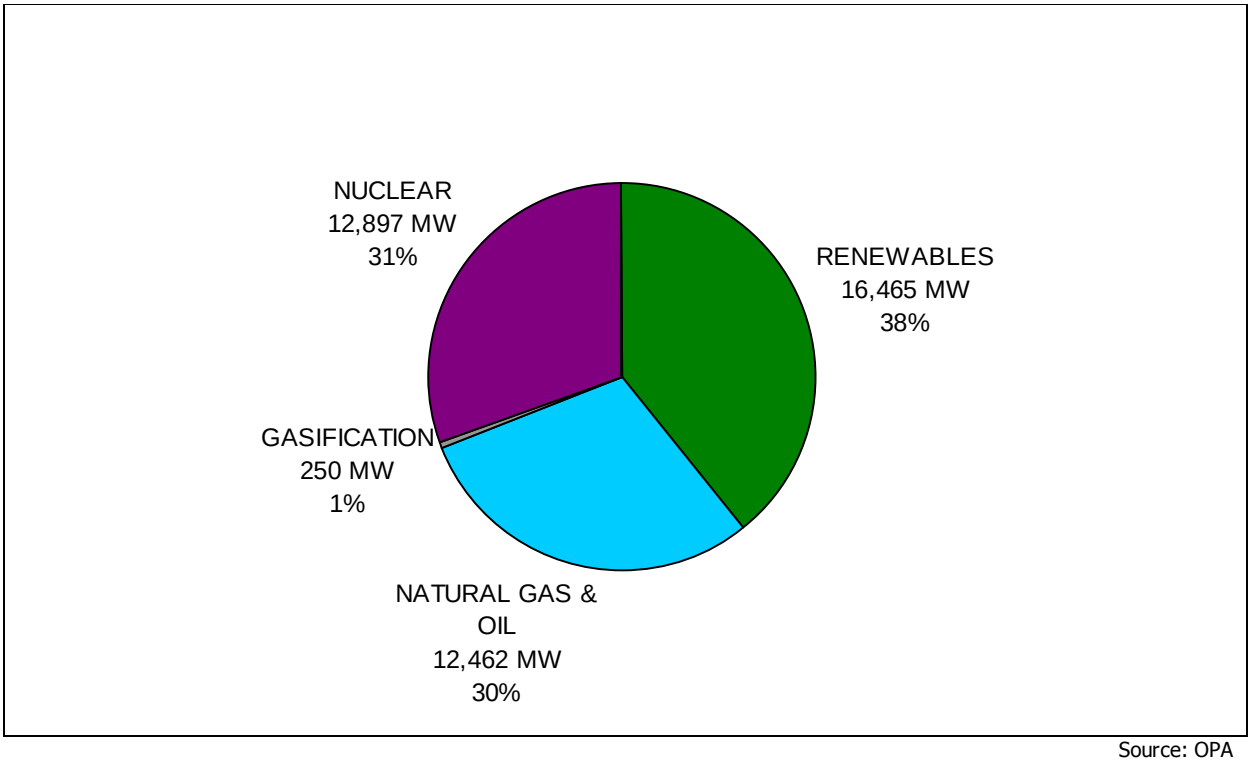
Source: OPA

Figure 2.8.28 – Portfolio 3B, Energy



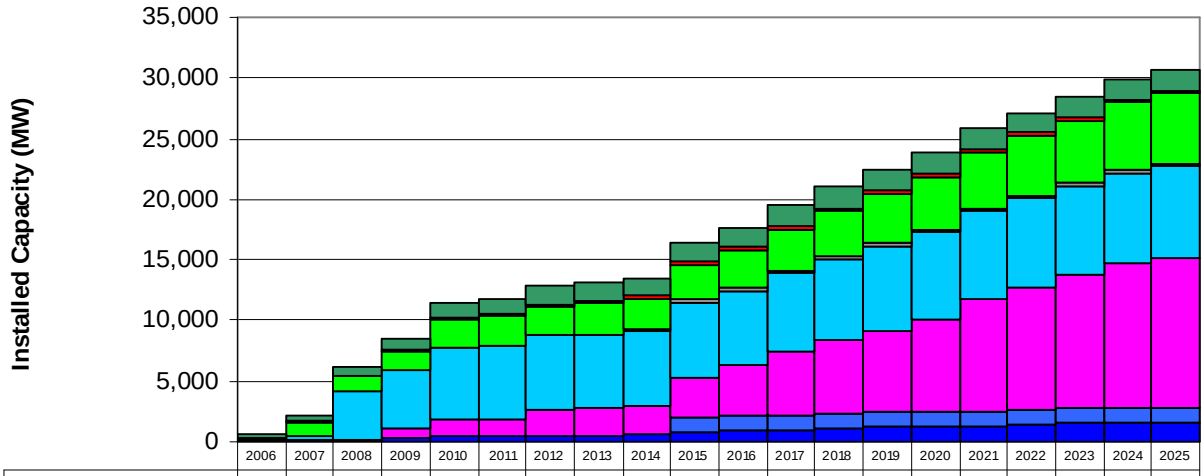
Source: OPA

Figure 2.8.29 – Portfolio 3B: Composition at 2025 (Installed)



Source: OPA

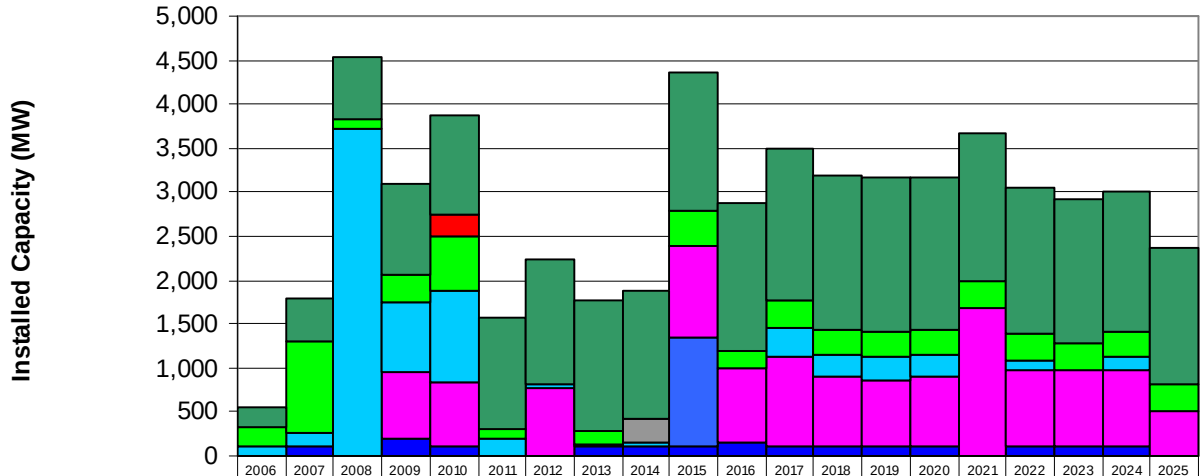
Table 2.8.26 – Portfolio 3B: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,500	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Natural Gas & Oil	117	272	3,992	4,786	5,826	6,026	6,066	6,106	6,166	6,166	6,166	6,496	6,746	6,996	7,246	7,246	7,346	7,346	7,486	7,486
New and/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	5,979	6,749	7,546	9,224	10,105	10,986	11,867	12,382
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	121	121	329	429	429	429	529	629	729	879	979	1,079	1,179	1,279	1,279	1,379	1,479	1,579	1,579

Source: OPA

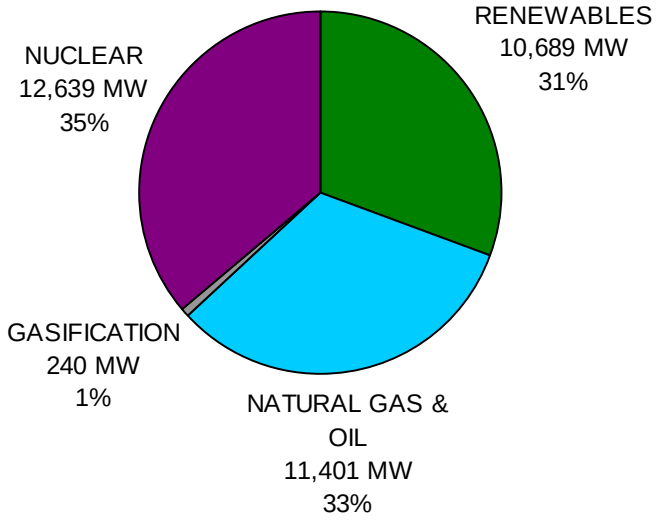
Table 2.8.27 – Portfolio 3B: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	150	0	400	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	250	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	117	155	3,720	794	1,040	200	40	40	60	0	0	330	250	250	250	0	100	0	140	0
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	797	770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	208	100	0	0	100	100	100	150	100	100	100	100	0	100	100	100	0

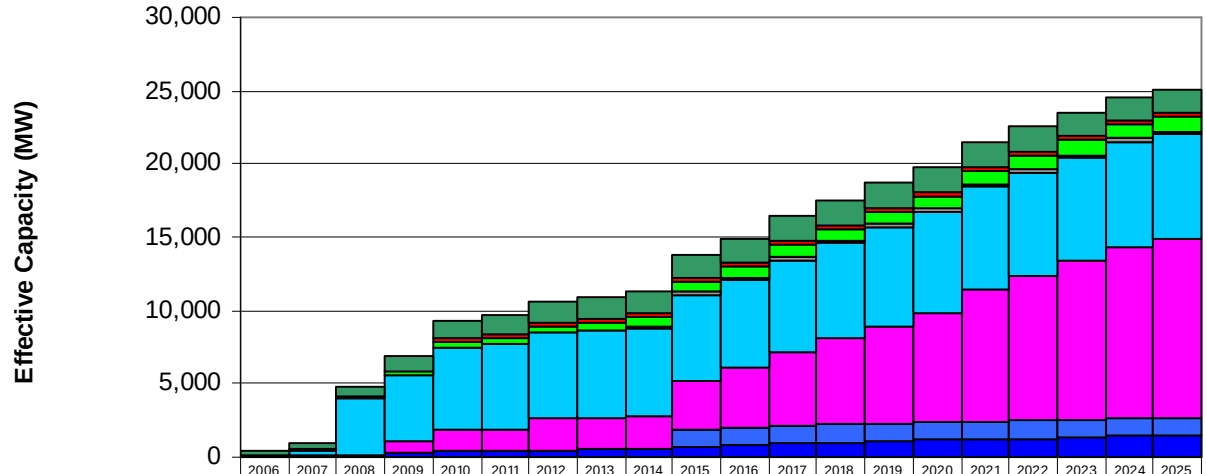
Source: OPA

Figure 2.8.30 – Portfolio 3B: Composition at 2025 (Effective)



Source: OPA

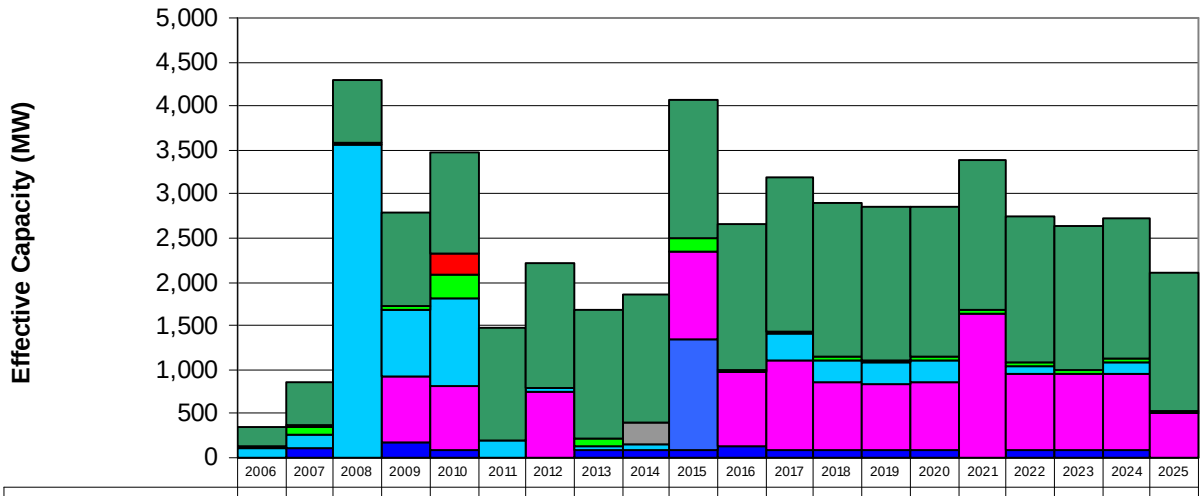
Table 2.8.28 – Portfolio 3B: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	548	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Natural Gas & Oil	112	261	3,832	4,595	5,593	5,785	5,823	5,862	5,919	5,919	5,919	6,236	6,476	6,716	6,956	6,956	7,052	7,052	7,187	7,187
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	5,859	6,614	7,395	9,040	9,903	10,766	11,630	12,134
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	108	108	296	386	386	386	476	566	656	791	881	971	1,061	1,151	1,151	1,241	1,331	1,421	1,421

Source: OPA

Table 2.8.29 – Portfolio 3B: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	232	487	711	1,048	1,135	1,271	1,412	1,473	1,474	1,575	1,676	1,739	1,747	1,743	1,719	1,690	1,664	1,630	1,598	1,558
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	90	0	140	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	240	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	3,571	762	998	192	38	38	58	0	0	317	240	240	240	0	96	0	134	0
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	781	755	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	187	90	0	0	90	90	90	135	90	90	90	90	0	90	90	90	0

Source: OPA

Table 2.8.30 – Portfolio 3B: Capacity at 2010, 2015, 2020, and 2025

3B Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,551	2,073	2,288	2,098
Renewables	7,839	9,604	10,239	10,689
Natural Gas & Oil	9,808	10,134	11,171	11,401
Gasification	0	240	240	240
Nuclear	11,884	10,797	10,131	12,639
Coal	3,748	0	0	0
Total	34,830	32,848	34,070	37,068
3B Installed Capacity (MW)	**2010**	**2015**	**2020**	**2025**
CDM	1,551	2,073	2,288	2,098
Renewables	10,480	12,685	14,635	16,465
Natural Gas & Oil	10,802	11,142	12,222	12,462
Gasification	0	250	250	250
Nuclear	12,127	11,017	10,338	12,897
Coal	3,945	0	0	0
Total	38,906	37,168	39,734	44,173

Source: OPA

2.8.4.7. Scenario 4, Portfolio 4A

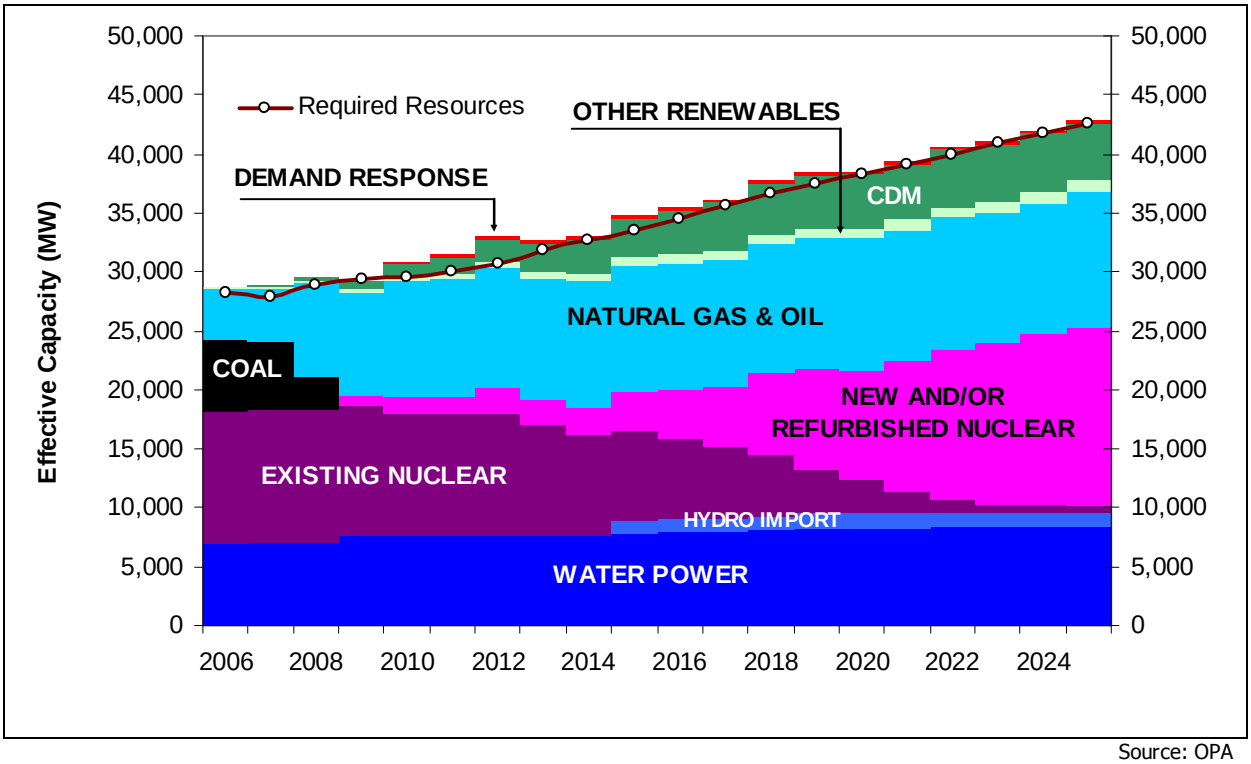
Portfolio 4A responds to a higher load growth scenario than assumed in scenarios 1 through 3. Under scenario 4, growth in electricity consumption and peak demand increases by 1.8% and by 2.15% per year, respectively. In addition to higher growth in demand, Portfolio 4A also sees a higher uptake of conservation and efficiency.

In Portfolio 4A, most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering, are refurbished or replaced as they reach the end of their estimated service lives. All of Ontario's coal-fired fleet is removed from service and replaced by 2009, and all of the common elements outlined in section 2.8.4 are added with the exception of gasification.

1,200 MW of additional gas-fired capacity is added over the study period. 3,000 MW of new nuclear capacity is also added.

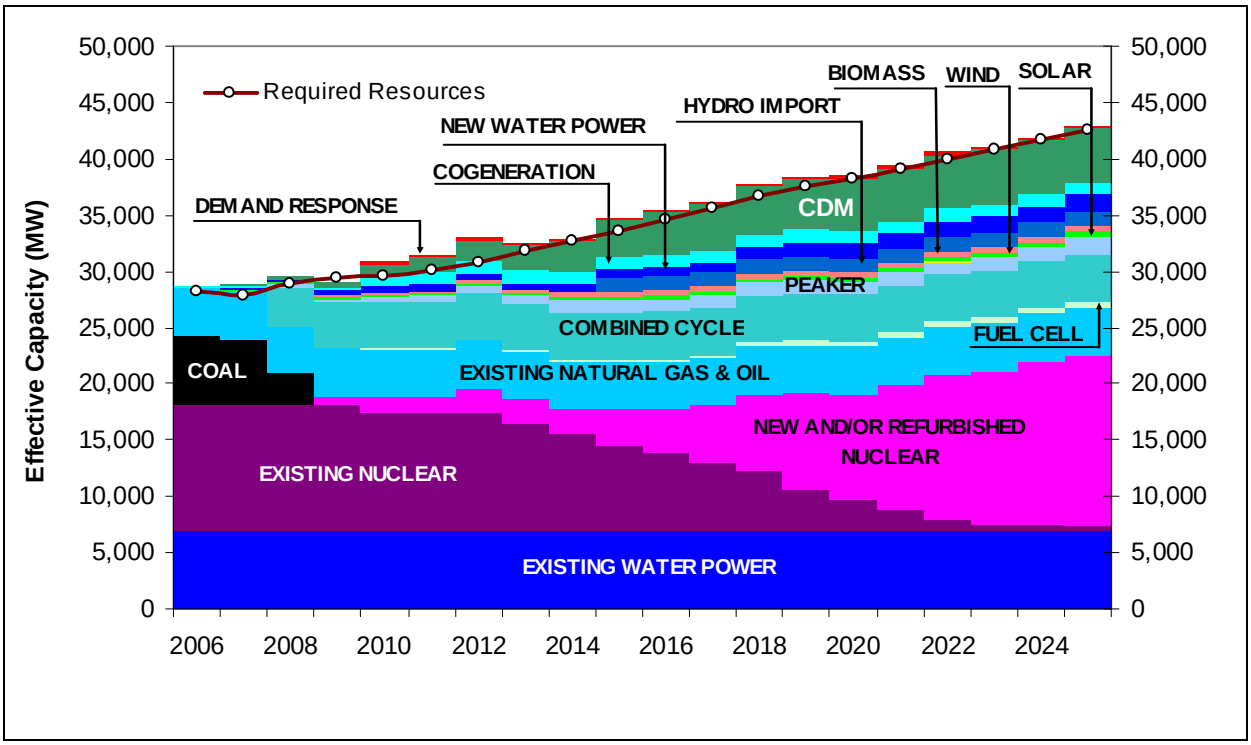
Figure 2.8.31 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.32. Energy production associated with the portfolio is shown in Figure 2.8.33. Figure 2.8.34 outlines the portfolio's composition at the year 2025. Tables 2.8.31 and 2.8.32 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.31 – Portfolio 4A



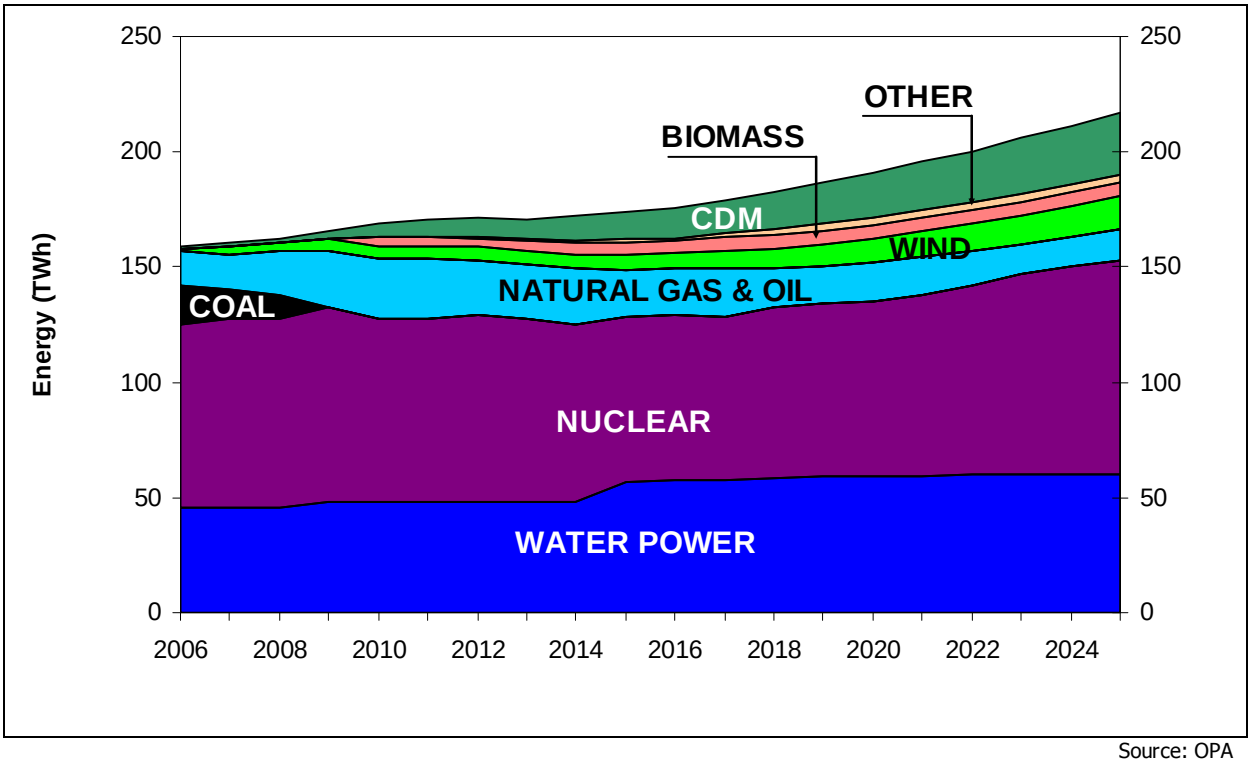
Source: OPA

Figure 2.8.32 – Portfolio 4A: Higher Resolution



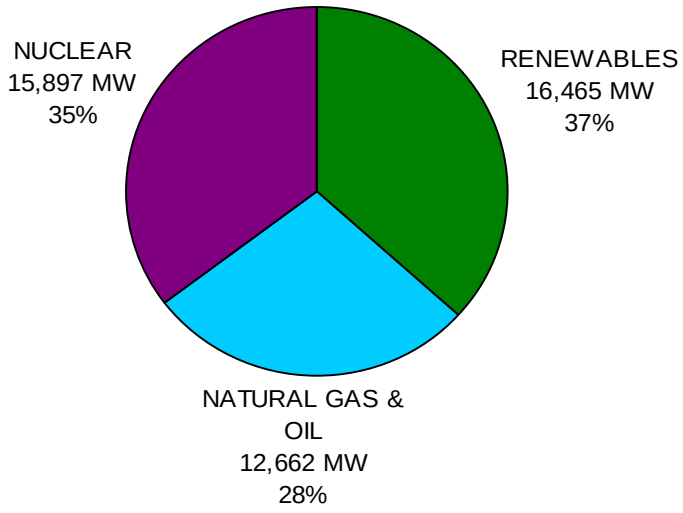
Source: OPA

Figure 2.8.33 – Portfolio 4A, Energy



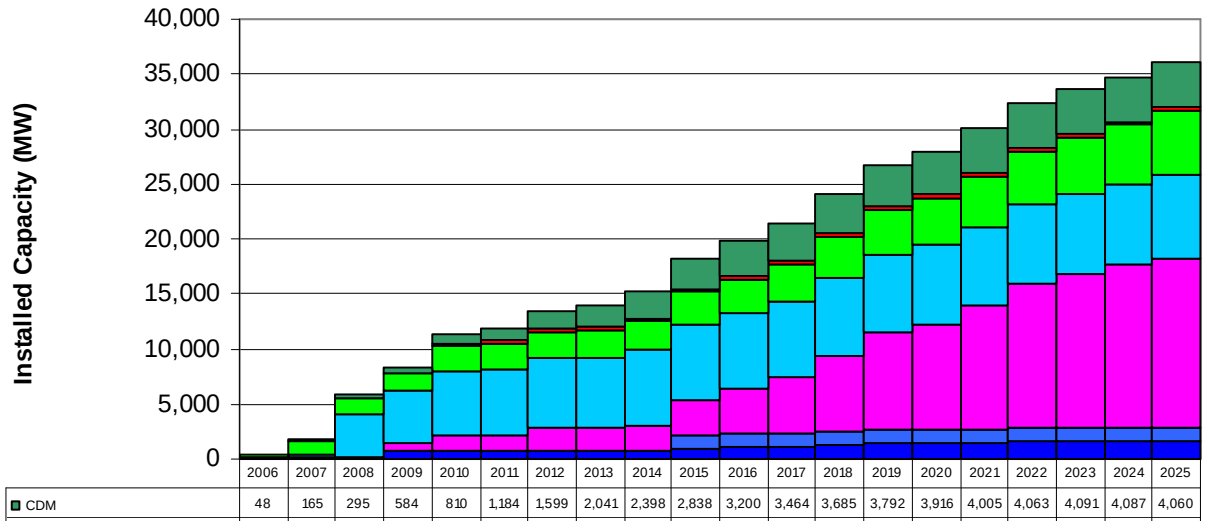
Source: OPA

Figure 2.8.34 – Portfolio 4A: Composition at 2025 (Installed)



Source: OPA

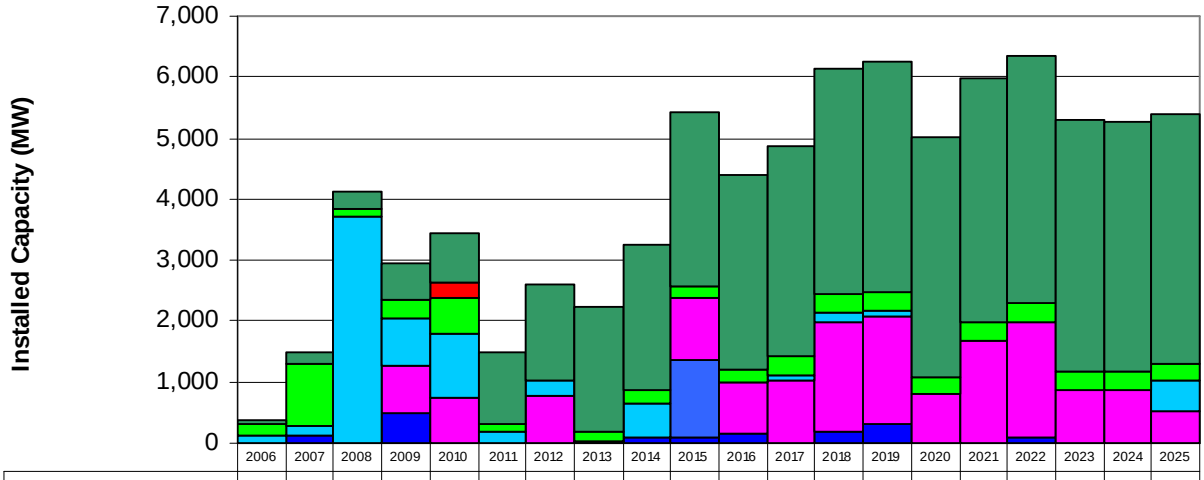
Table 2.8.31 – Portfolio 4A: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,700	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	117	272	3,992	4,786	5,826	6,026	6,266	6,306	6,866	6,866	6,866	6,946	7,086	7,186	7,186	7,186	7,186	7,186	7,186	7,686
Newand/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	6,979	8,749	9,546	11,224	13,105	13,986	14,867	15,382
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
NewWater Power	0	121	121	629	629	629	629	629	729	829	979	979	1,179	1,479	1,479	1,479	1,579	1,579	1,579	1,579

Source: OPA

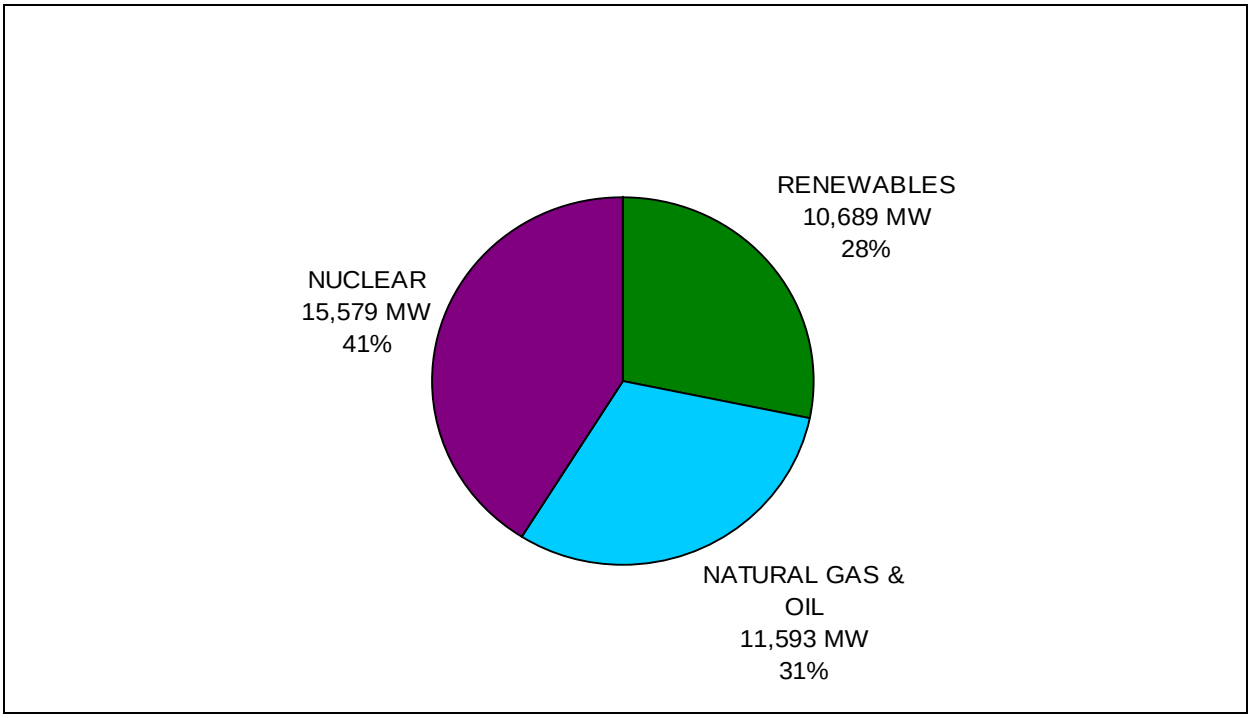
Table 2.8.32 – Portfolio 4A: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	150	200	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	117	155	3,720	794	1,040	200	240	40	560	0	0	80	140	100	0	0	0	0	0	500
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	1,797	1,770	797	1,678	1,881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	508	0	0	0	0	100	100	150	0	200	300	0	0	100	0	0	0

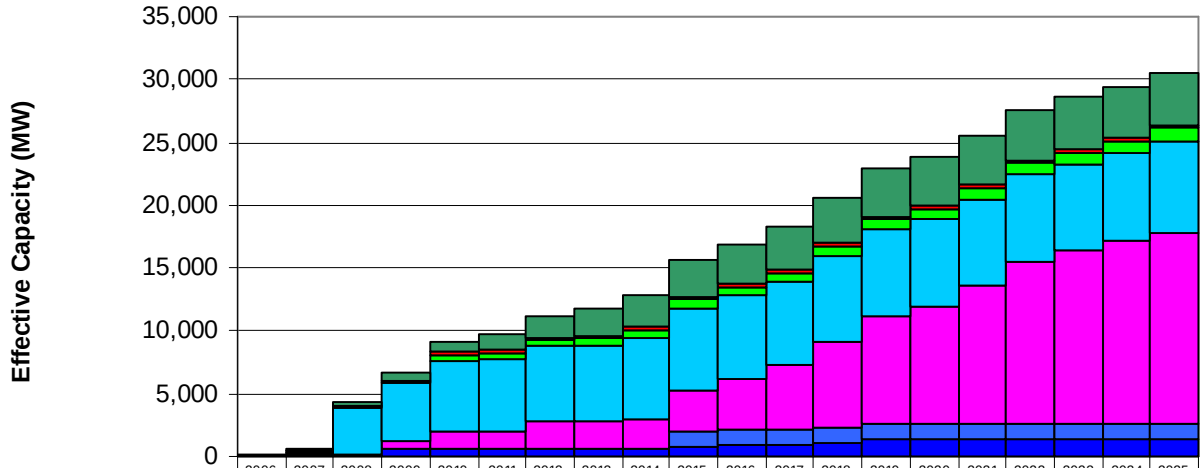
Source: OPA

Figure 2.8.35 – Portfolio 4A: Composition at 2025 (Effective)



Source: OPA

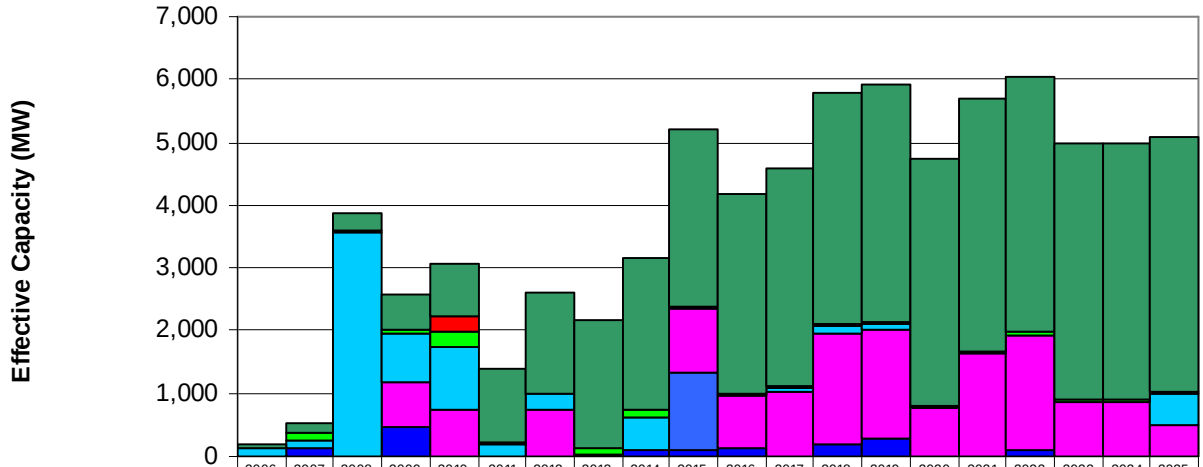
Table 2.8.33 – Portfolio 4A: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	668	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	261	3,832	4,595	5,593	5,785	6,015	6,054	6,591	6,591	6,591	6,668	6,803	6,899	6,899	6,899	6,899	6,899	6,899	7,379
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	6,839	8,574	9,355	11,000	12,843	13,706	14,570	15,074
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	108	108	566	566	566	566	566	656	746	881	881	1,061	1,331	1,331	1,331	1,421	1,421	1,421	1,421

Source: OPA

Table 2.8.34 – Portfolio 4A: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	90	120	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	3,571	762	998	192	230	38	538	0	0	77	134	96	0	0	0	0	0	480
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	1,761	1,735	781	1,644	1,843	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	90	90	135	0	180	270	0	0	90	0	0	0

Source: OPA

Table 2.8.35 – Portfolio 4A: Capacity at 2010, 2015, 2020, and 2025

4A Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,182	3,527	4,881	5,051
Renewables	8,019	9,694	10,419	10,689
Natural Gas & Oil	9,808	10,806	11,113	11,593
Gasification	0	0	0	0
Nuclear	11,884	10,797	12,091	15,579
Coal	0	0	0	0
Total	30,893	34,824	38,505	42,912

4A Installed Capacity (MW)	2010	2015	2020	2025
CDM	1,182	3,527	4,881	5,051
Renewables	10,680	12,785	14,835	16,465
Natural Gas & Oil	10,802	11,842	12,162	12,662
Gasification	0	0	0	0
Nuclear	12,127	11,017	12,338	15,897
Coal	0	0	0	0
Total	34,791	39,172	44,217	50,075

Source: OPA

2.8.4.8. Scenario 4, Portfolio 4B

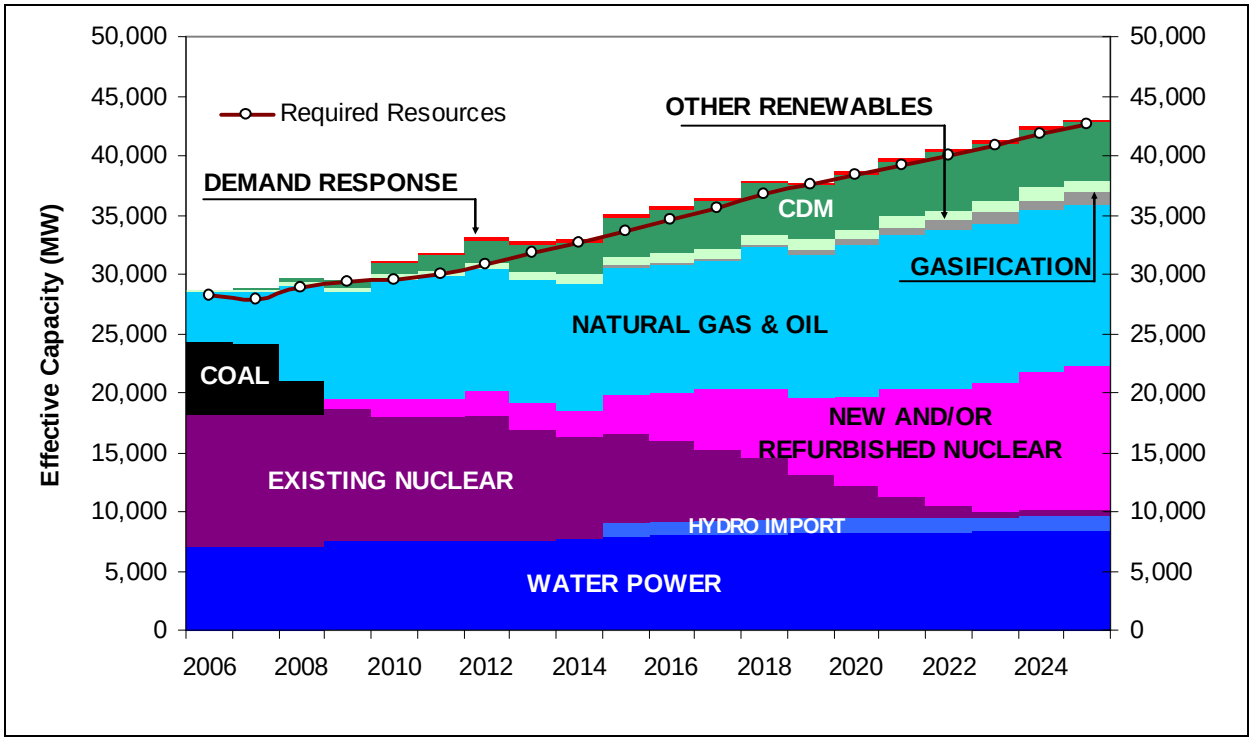
Like Portfolio 4A, Portfolio 4B responds to a growth in electricity consumption and peak demand of 1.8% and 2.15% per year, respectively. Similarly, Portfolio 4B sees a higher uptake of conservation and efficiency.

In Portfolio 4B, most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering, are refurbished or replaced as they reach the end of their estimated service lives. All of Ontario's coal-fired fleet is removed from service and replaced by 2009, and all of the common elements outlined in section 2.8.4 are added.

Unlike Portfolio 4A, Portfolio 4B does not contain any additional nuclear generation. Instead, approximately 2,400 MW of additional natural gas-fired capacity is added, along with 1,000 MW of new gasification.

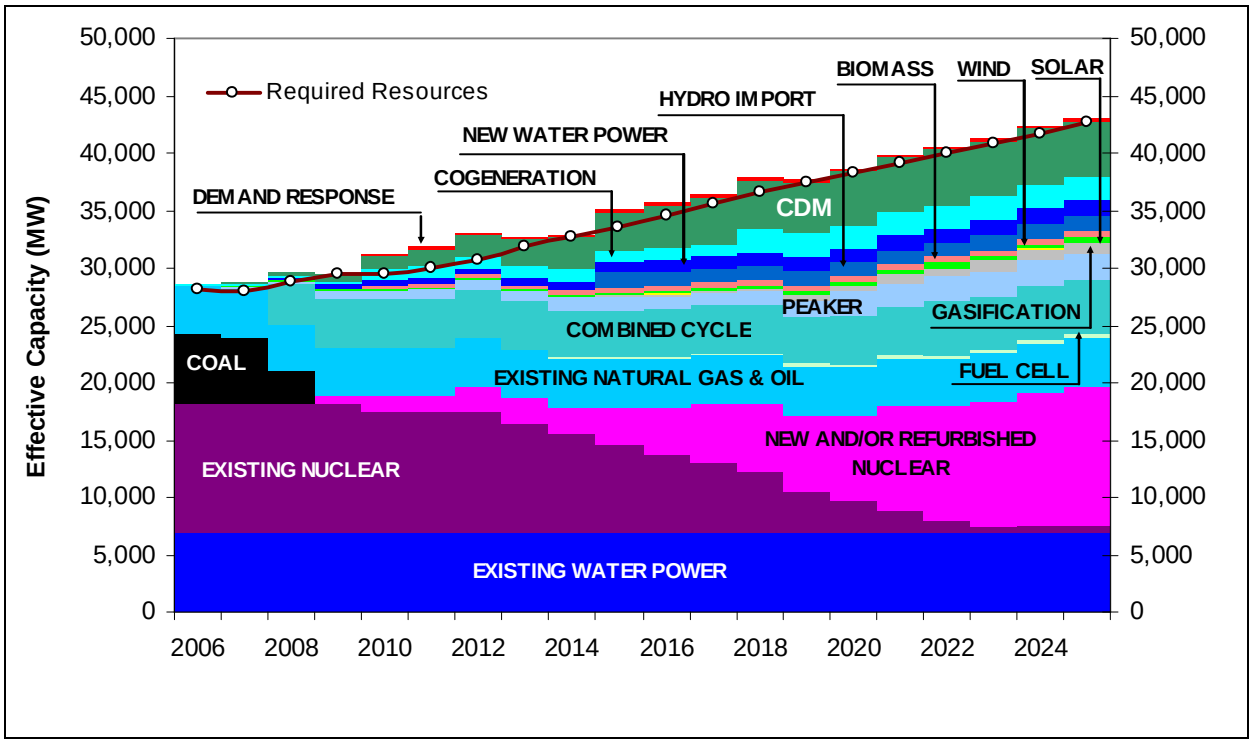
Figure 2.8.36 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.37. Energy production associated with the portfolio is shown in Figure 2.8.38. Figure 2.8.39 outlines the portfolio's composition at the year 2025. Tables 2.8.36 and 2.8.37 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.36 – Portfolio 4B



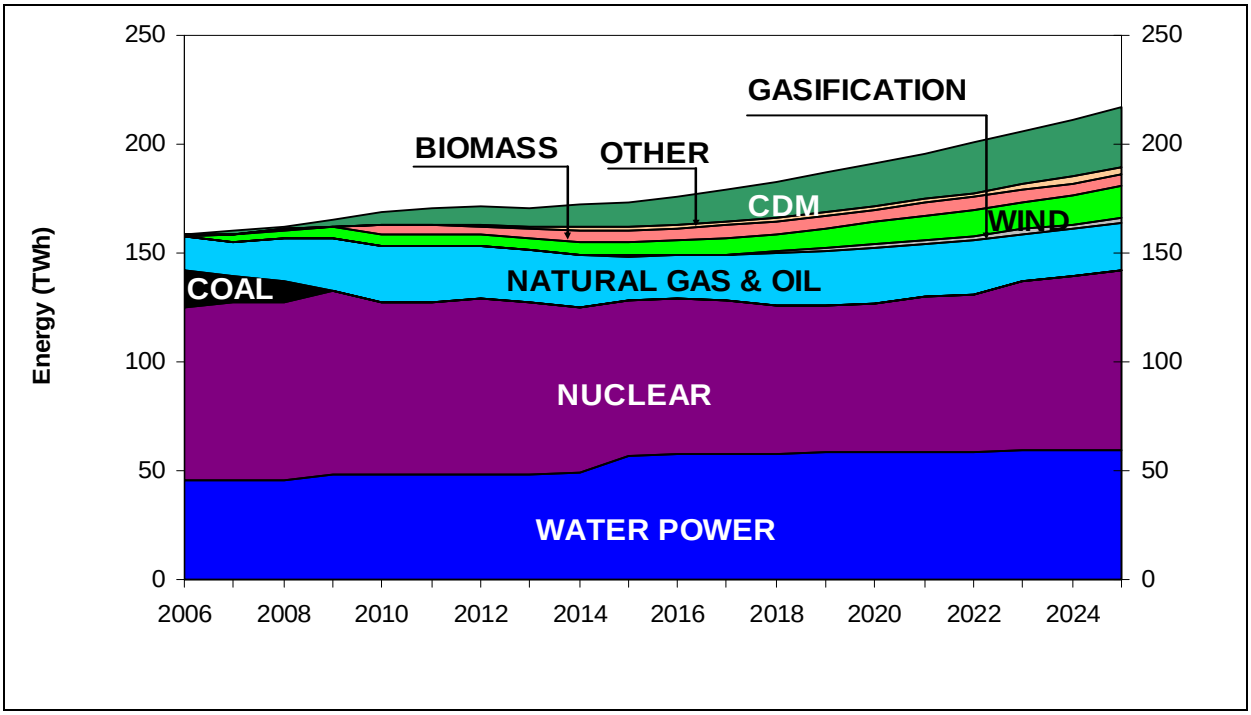
Source: OPA

Figure 2.8.37 – Portfolio 4B: Higher Resolution



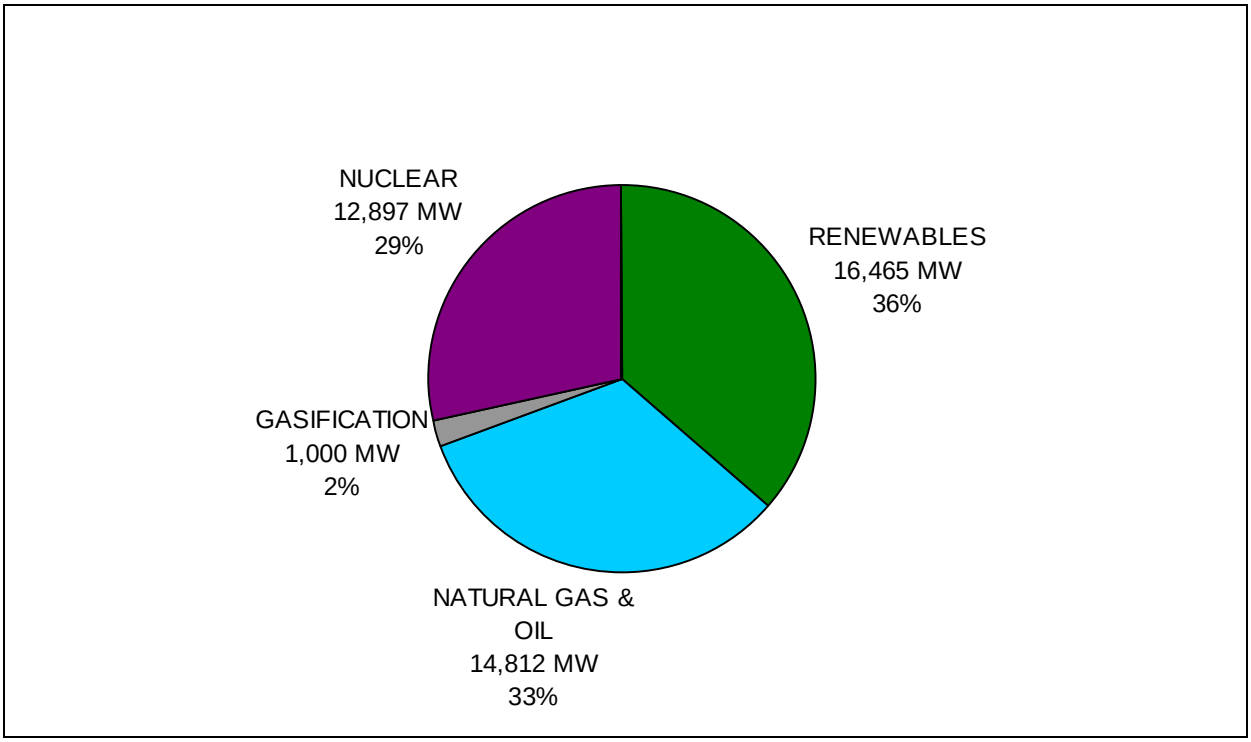
Source: OPA

Figure 2.8.38 – Portfolio 4B, Energy



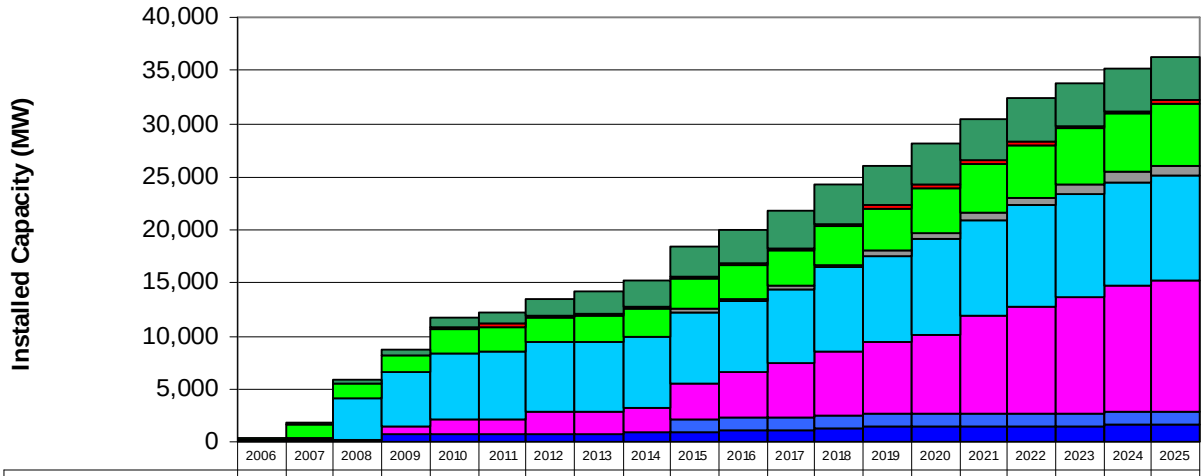
Source: OPA

Figure 2.8.39 – Portfolio 4B: Composition at 2025 (Installed)



Source: OPA

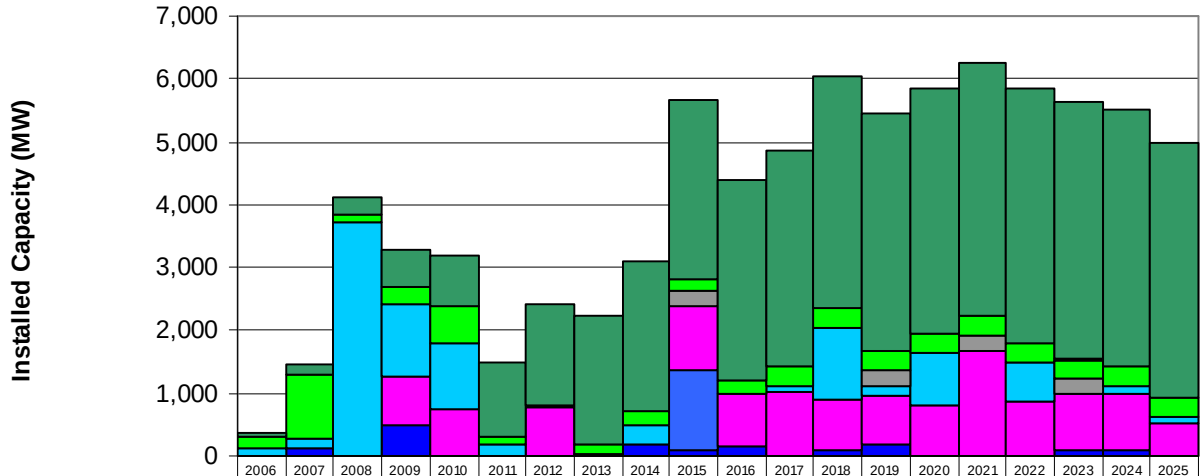
Table 2.8.36 – Portfolio 4B: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,700	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	0	250	250	250	250	500	500	750	750	1,000	1,000	1,000
Natural Gas & Oil	117	272	3,992	5,136	6,176	6,376	6,416	6,456	6,766	6,766	6,766	6,846	7,996	8,146	8,996	8,996	9,596	9,596	9,736	9,836
New and/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	5,979	6,749	7,546	9,224	10,105	10,986	11,867	12,382
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
New Water Power	0	121	121	629	629	629	629	629	829	929	1,079	1,079	1,179	1,379	1,379	1,379	1,379	1,479	1,579	1,579

Source: OPA

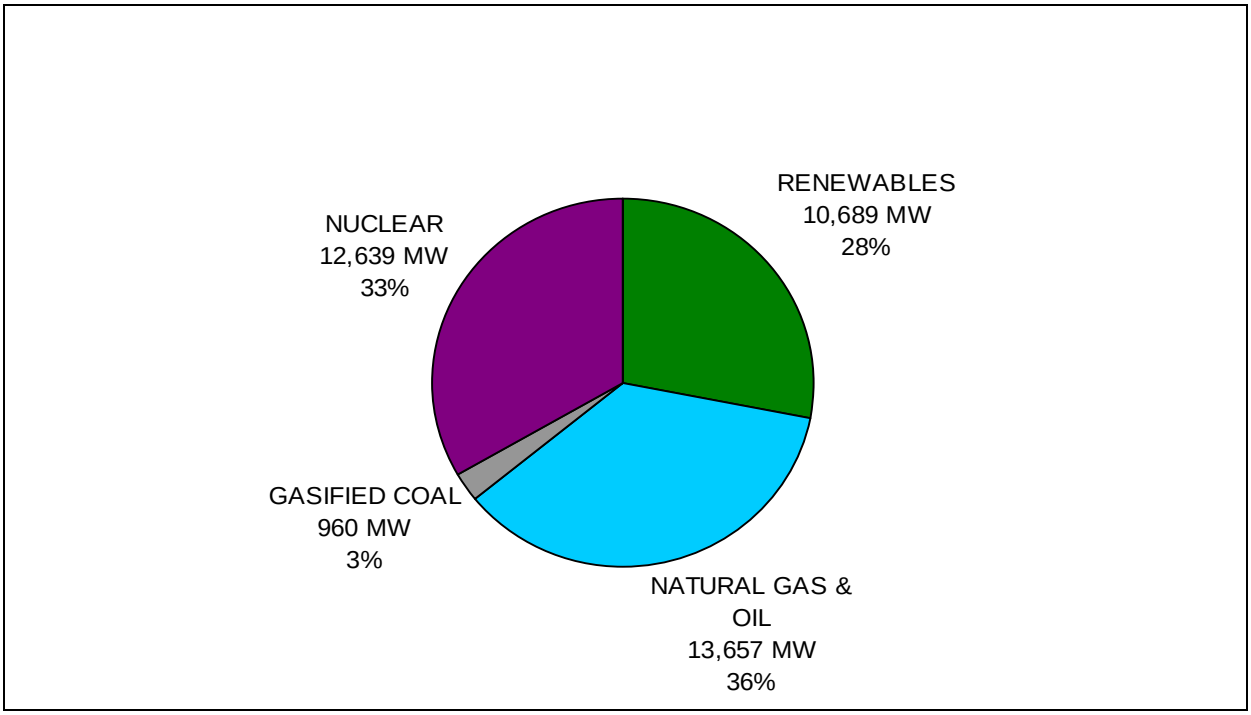
Table 2.8.37 – Portfolio 4B: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	0	0	5	0	0	5	0	0	0	0	0	0	0	0	10	10	10	0	0
Other Renewables	206	1,027	108	300	600	100	0	150	200	200	200	300	300	300	300	300	300	300	300	300
Gasification	0	0	0	0	0	0	0	0	0	250	0	0	0	250	0	250	0	250	0	0
Natural Gas & Oil	117	155	3,720	1,144	1,040	200	40	40	310	0	0	80	1,150	150	850	0	600	0	140	100
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	797	770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	508	0	0	0	0	200	100	150	0	100	200	0	0	0	100	100	0

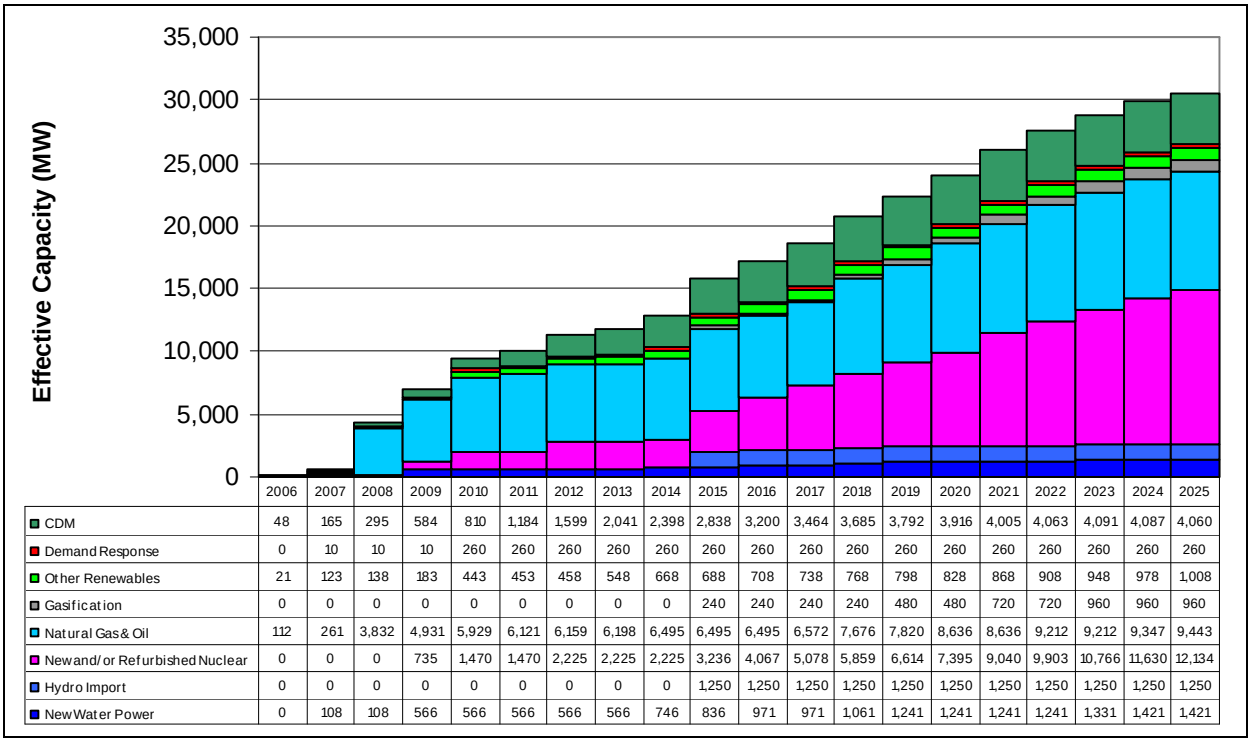
Source: OPA

Figure 2.8.40 – Portfolio 4B: Composition at 2025 (Effective)



Source: OPA

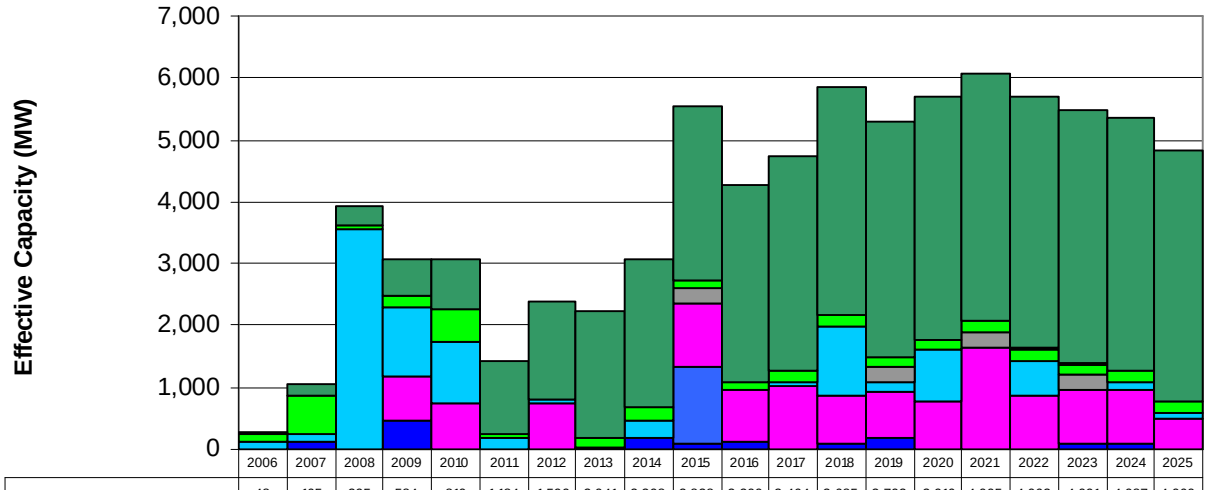
Table 2.8.38 – Portfolio 4B: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	668	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	0	240	240	240	240	480	480	720	720	960	960	960
Natural Gas& Oil	112	261	3,832	4,931	5,929	6,121	6,159	6,198	6,495	6,495	6,495	6,572	7,676	7,820	8,636	8,636	9,212	9,212	9,347	9,443
Newand/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	5,859	6,614	7,395	9,040	9,903	10,766	11,630	12,134
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
NewWater Power	0	108	108	566	566	566	566	566	746	836	971	971	1,061	1,241	1,241	1,241	1,241	1,331	1,421	1,421

Source: OPA

Table 2.8.39 – Portfolio 4B: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,041	2,398	2,838	3,200	3,464	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	0	0	5	0	0	5	0	0	0	0	0	0	0	0	10	10	10	0	0
Other Renewables	124	616	68	188	520	60	0	150	200	120	120	180	180	180	180	180	180	180	180	180
Gasification	0	0	0	0	0	0	0	0	0	240	0	0	0	240	0	240	0	240	0	0
Natural Gas & Oil	112	149	3,571	1,098	998	192	38	38	298	0	0	77	1,104	144	816	0	576	0	134	96
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	781	755	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	1,250	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	180	90	135	0	90	180	0	0	0	90	90	0

Source: OPA

Table 2.8.40 – Portfolio 4B: Capacity at 2010, 2015, 2020, and 2025

Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,182	3,527	4,881	5,051
Renewables	8,019	9,784	10,329	10,689
Natural Gas & Oil	10,144	10,710	12,851	13,657
Gasification	0	240	480	960
Nuclear	11,884	10,797	10,131	12,639
Coal	0	0	0	0
Total	31,229	35,058	38,672	42,996

Installed Capacity (MW)	2010	2015	2020	2025
CDM	1,182	3,527	4,881	5,051
Renewables	10,680	12,885	14,735	16,465
Natural Gas & Oil	11,152	11,742	13,972	14,812
Gasification	0	250	500	1,000
Nuclear	12,127	11,017	10,338	12,897
Coal	0	0	0	0
Total	35,141	39,422	44,427	50,225

Source: OPA

2.8.4.9. Scenario 5, Portfolio 5A

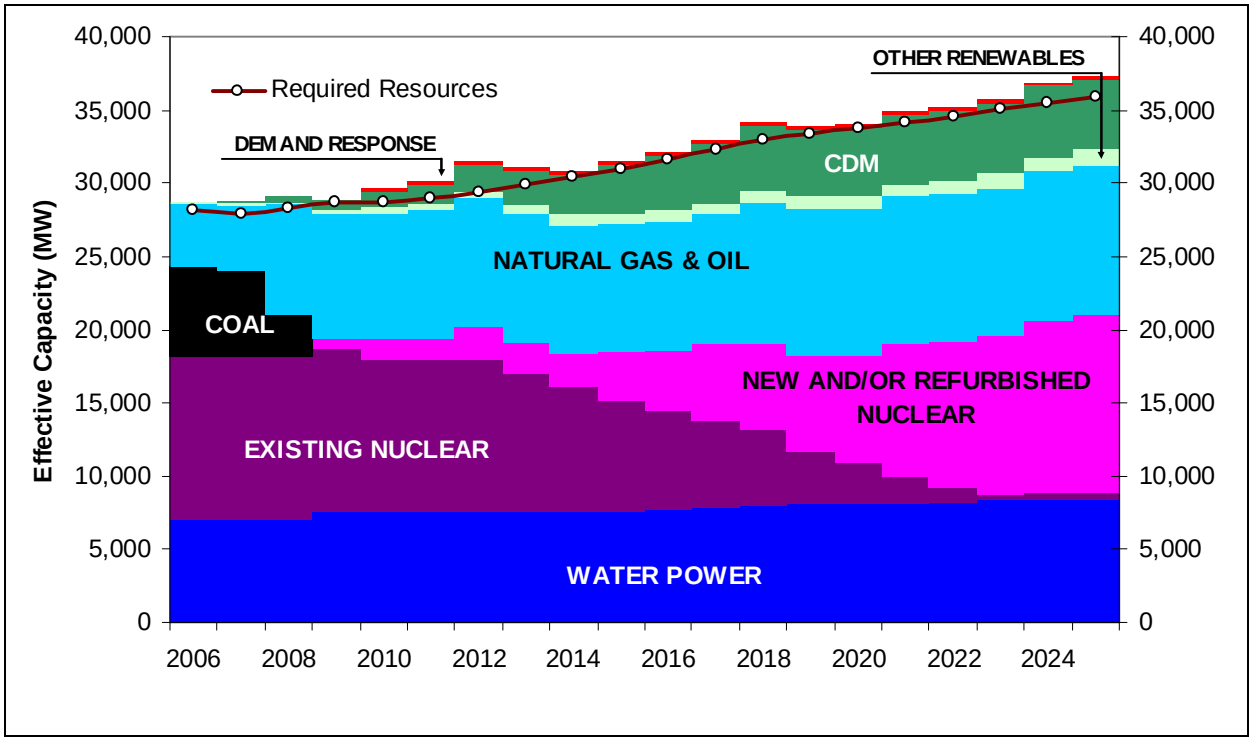
Portfolio 5A responds to a scenario that sees higher success in capturing conservation and demand management potential of up to 4,000 MW.

Portfolio 5A assumes the higher conservation is recognized now and therefore does not include any out-of-province firm purchases, and sees a 200 MW reduction of natural gas-fired generation contemplated under government procurements. In addition, approximately 1,400 MW of the natural gas-fired procurements are deferred until 2018 through 2019. All of the other common elements outlined above are included, with the exception of gasification and with a higher contribution from conservation and demand management.

Most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering, are refurbished or replaced as they reach the end of their estimated service lives. All of Ontario's coal-fired fleet is removed from service by 2009.

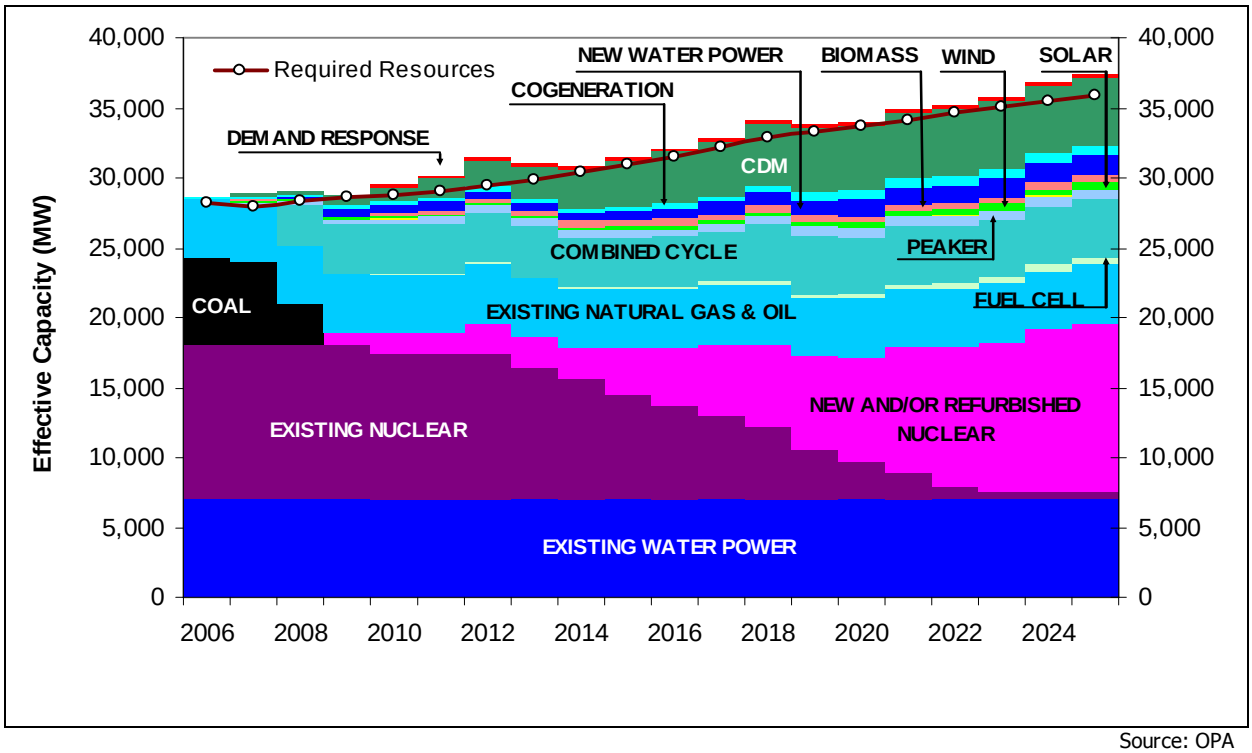
Figure 2.8.41 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.42. Energy production associated with the portfolio is shown in Figure 2.8.43. Figure 2.8.44 outlines the portfolio's composition at the year 2025. Tables 2.8.41 and 2.8.42 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.41 – Portfolio 5A



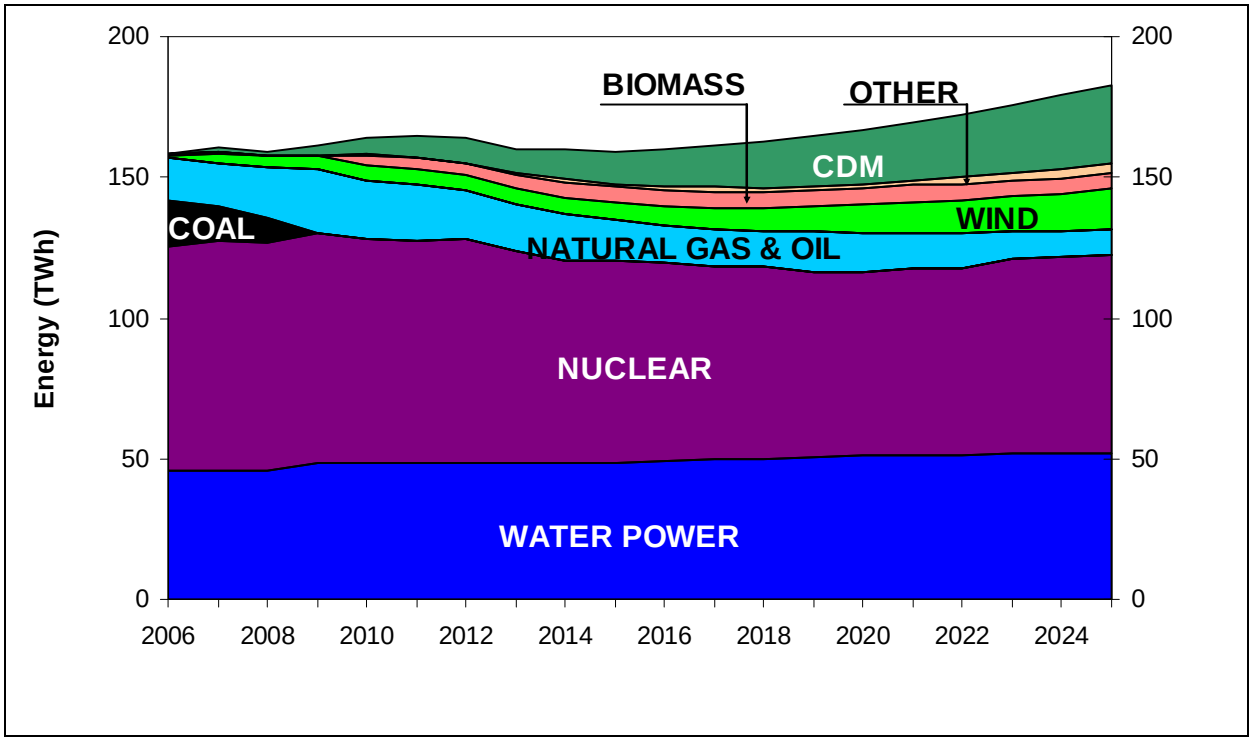
Source: OPA

Figure 2.8.42 – Portfolio 5A: Higher Resolution



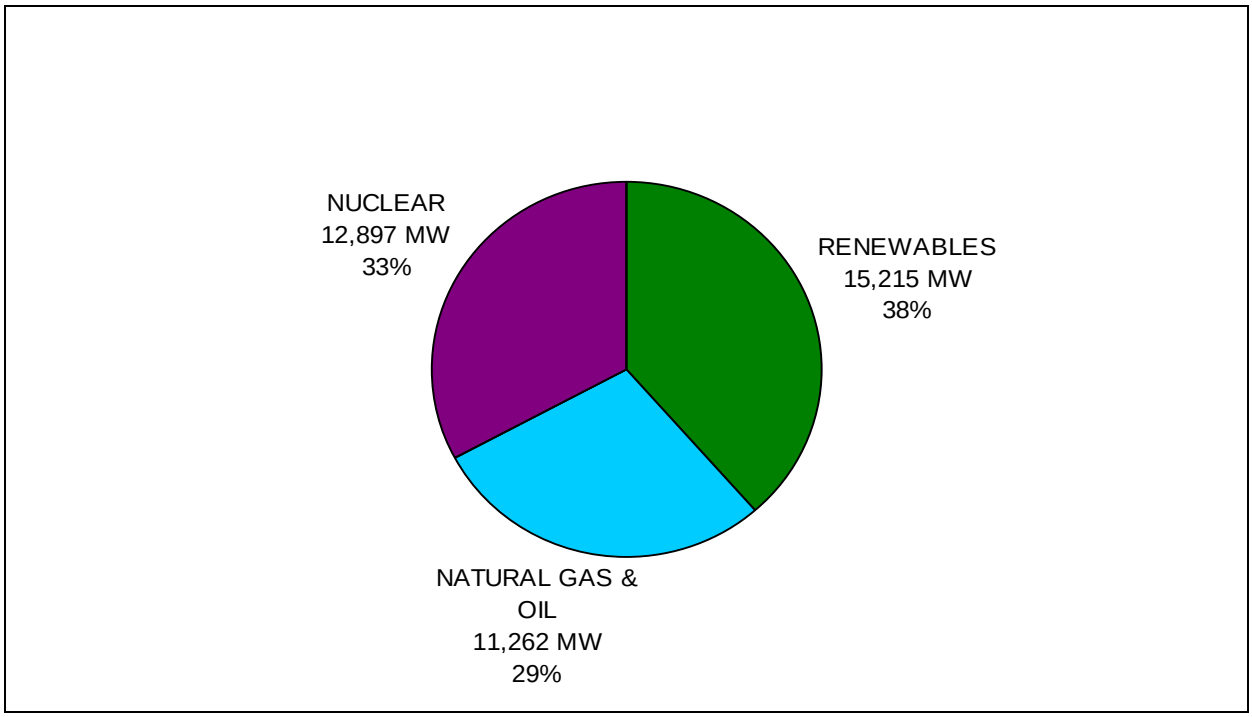
Source: OPA

Figure 2.8.43 – Portfolio 5A, Energy



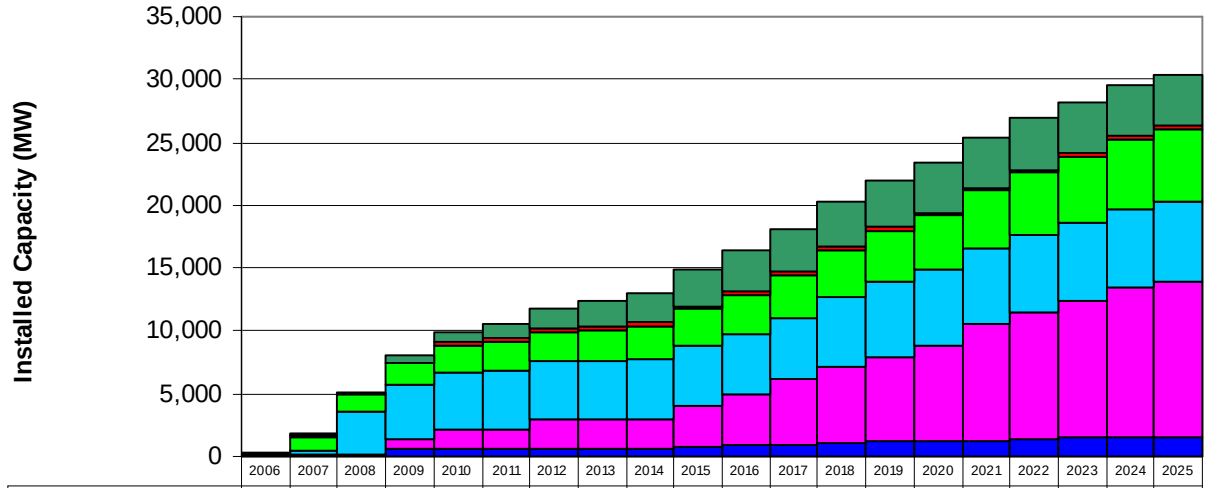
Source: OPA

Figure 2.8.44 – Portfolio 5A: Composition at 2025 (Installed)



Source: OPA

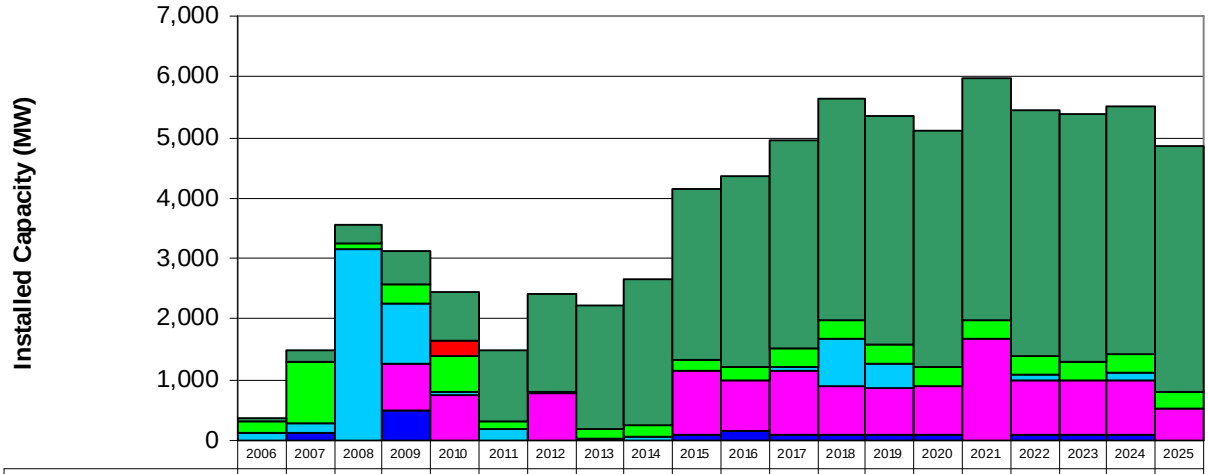
Table 2.8.41 – Portfolio 5A: Cumulative New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,700	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas& Oil	117	272	3,422	4,416	4,456	4,656	4,696	4,736	4,796	4,796	4,796	4,876	5,646	6,046	6,046	6,046	6,146	6,146	6,286	6,286
New and/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	5,979	6,749	7,546	9,224	10,105	10,986	11,867	12,382
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	121	629	629	629	629	629	629	729	879	979	1,079	1,179	1,279	1,279	1,379	1,479	1,579	1,579

Source: OPA

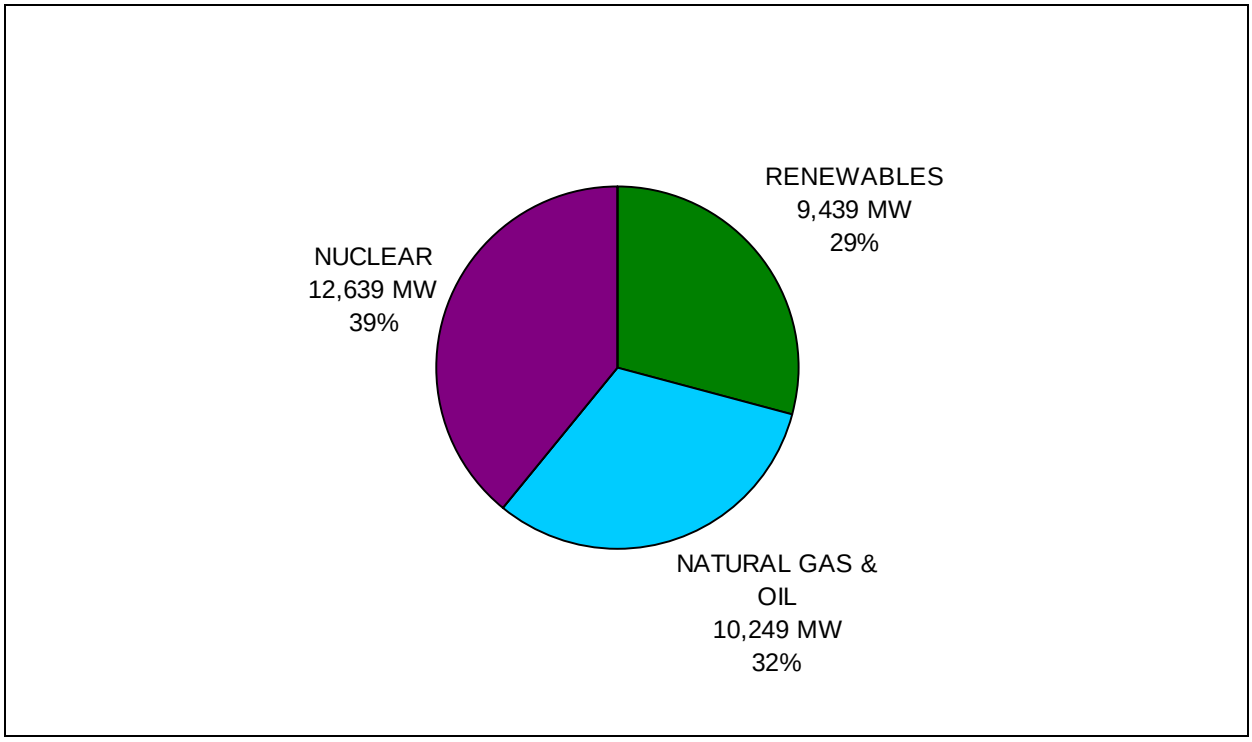
Table 2.8.42 – Portfolio 5A: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	150	200	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas& Oil	117	155	3,150	994	40	200	40	40	60	0	0	80	770	400	0	0	100	0	140	0
New and/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	797	770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	0	508	0	0	0	0	0	100	150	100	100	100	100	0	100	100	100	0

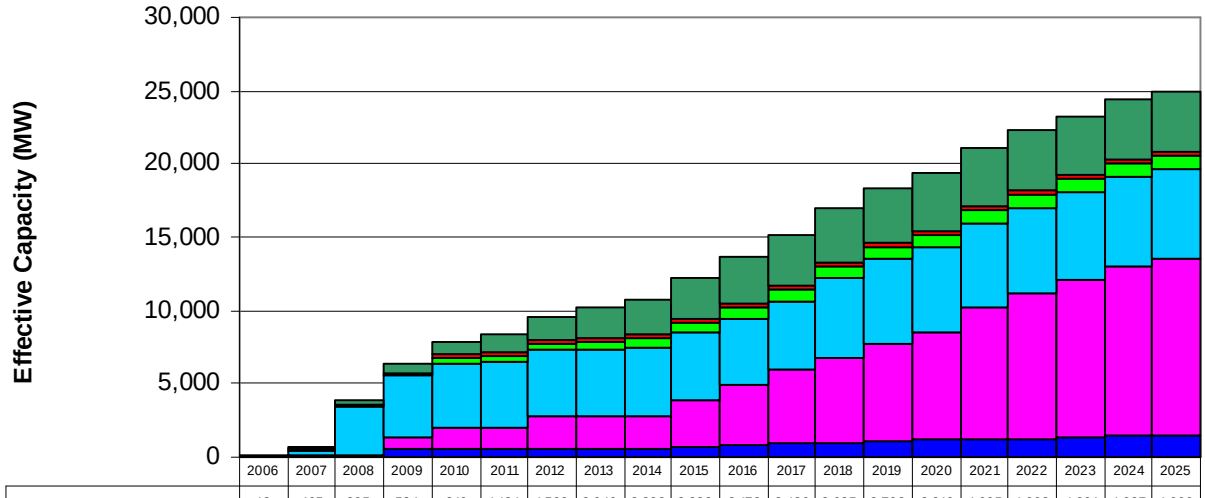
Source: OPA

Figure 2.8.45 – Portfolio 5A: Composition at 2025 (Effective)



Source: OPA

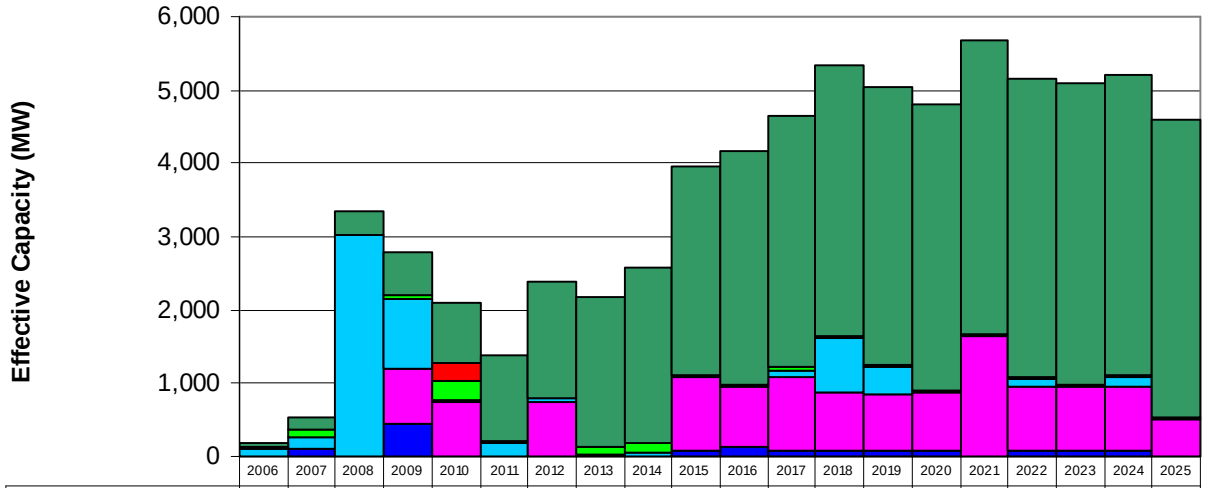
Table 2.8.43 – Portfolio 5A: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	668	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	261	3,285	4,239	4,278	4,470	4,508	4,547	4,604	4,604	4,604	4,681	5,420	5,804	5,804	5,804	5,900	5,900	6,035	6,035
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	5,859	6,614	7,395	9,040	9,903	10,766	11,630	12,134
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	108	566	566	566	566	566	566	656	791	881	971	1,061	1,151	1,151	1,241	1,331	1,421	1,421

Source: OPA

Table 2.8.44 – Portfolio 5A: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	90	120	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	3,024	954	38	192	38	38	58	0	0	77	739	384	0	0	96	0	134	0
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	781	755	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	0	90	135	90	90	90	90	0	90	90	90	0

Source: OPA

Table 2.8.45 – Portfolio 5A: Capacity at 2010, 2015, 2020, and 2025

5A Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,181	3,515	4,881	5,051
Renewables	8,019	8,354	8,989	9,439
Natural Gas & Oil	8,492	8,819	10,019	10,249
Gasification	0	0	0	0
Nuclear	11,884	10,797	10,131	12,639
Coal	0	0	0	0
Total	29,577	31,485	34,020	37,378

5A Installed Capacity (MW)	2010	2015	2020	2025
CDM	1,181	3,515	4,881	5,051
Renewables	10,680	11,435	13,385	15,215
Natural Gas & Oil	9,432	9,772	11,022	11,262
Gasification	0	0	0	0
Nuclear	12,127	11,017	10,338	12,897
Coal	0	0	0	0
Total	33,421	35,740	39,627	44,425

Source: OPA

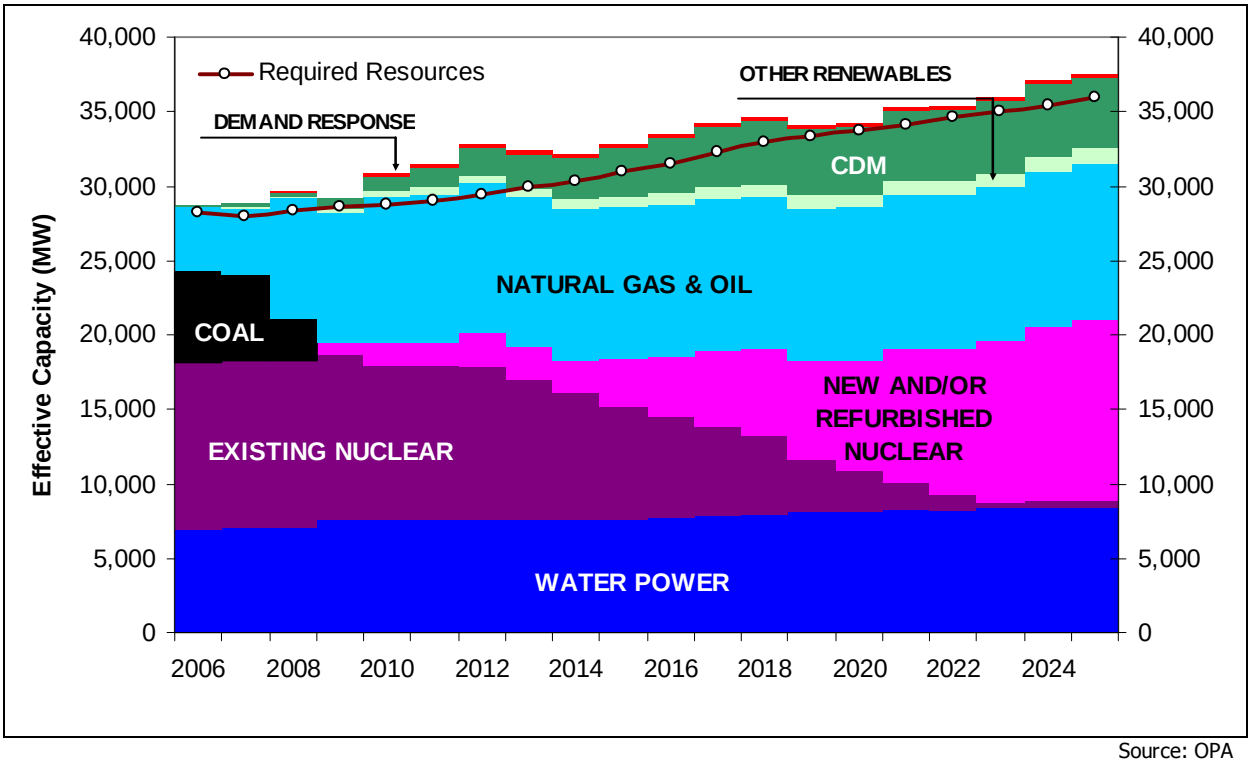
2.8.4.10. Scenario 5, Portfolio 5B

Like Portfolio 5A, Portfolio 5B sees higher conservation and demand management. Unlike Portfolio 5A, however, Portfolio 5B assumes the potential is recognized three years from now and therefore does not reduce or defer any natural gas-fired generation contemplated under government procurements.

In Portfolio 5B, most of Ontario's nuclear units, with the exception of units 2 and 3 at Pickering, are refurbished or replaced. Most of the common elements outlined above are included, with the exception of gasification and any out-of-province purchases. The entirety of Ontario's coal-fired fleet is removed from service and replaced by 2009.

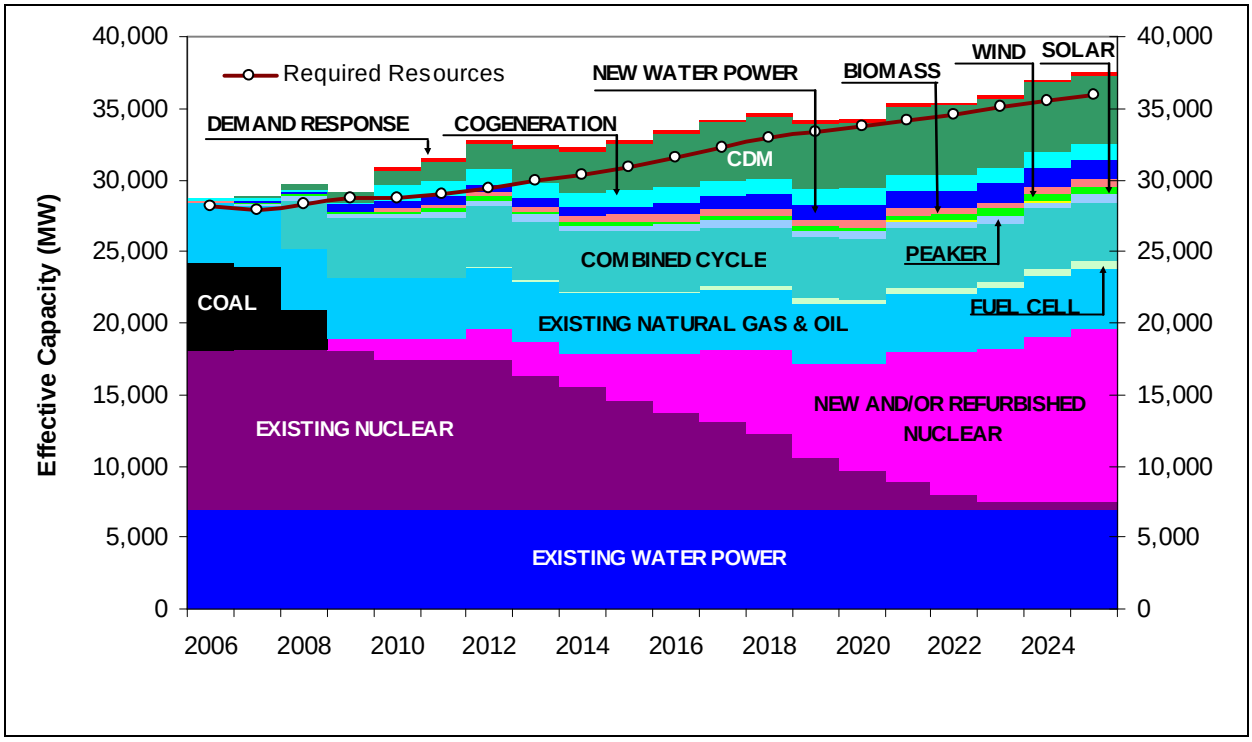
Figure 2.8.46 illustrates the portfolio between 2006 and 2025. The portfolio is illustrated with higher resolution in Figure 2.8.47. Energy production associated with the portfolio is shown in Figure 2.8.48. Figure 2.8.49 outlines the portfolio's composition at the year 2025. Tables 2.8.46 and 2.8.47 outline the resource additions assumed over the study period. The remaining figures and tables describe the portfolio in effective terms.

Figure 2.8.46 – Portfolio 5B



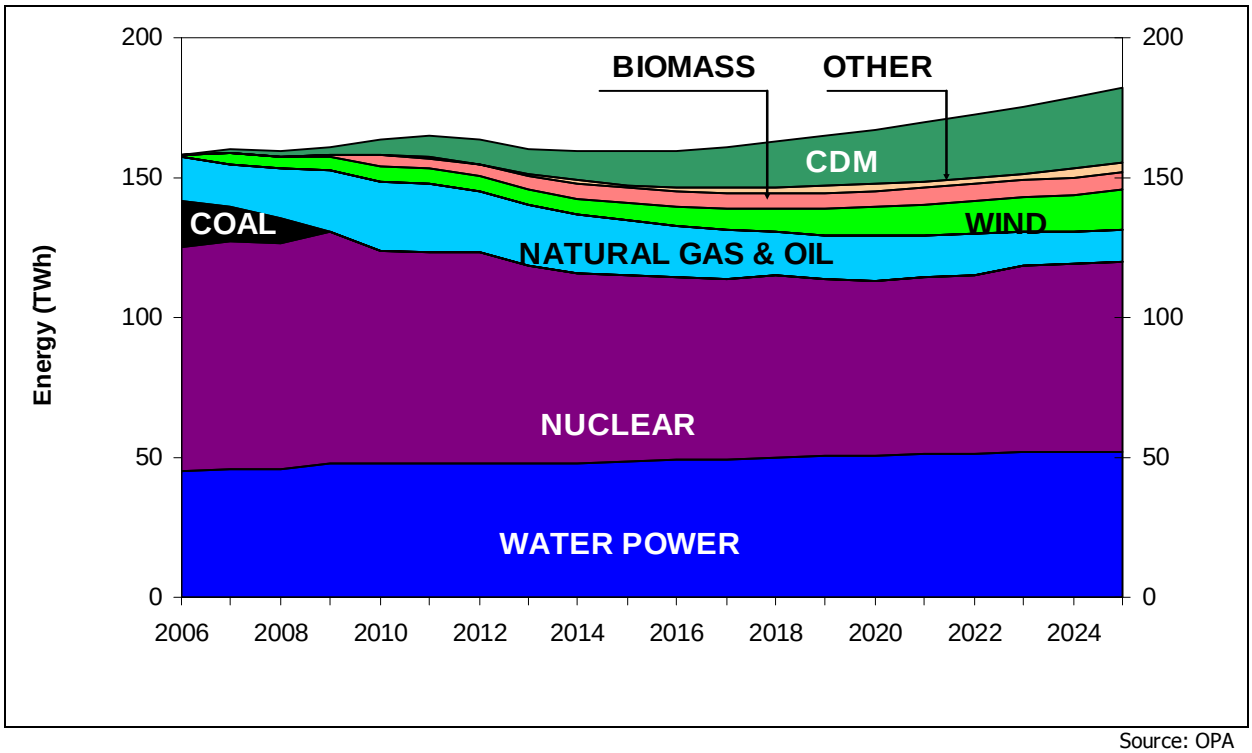
Source: OPA

Figure 2.8.47 – Portfolio 5B: Higher Resolution



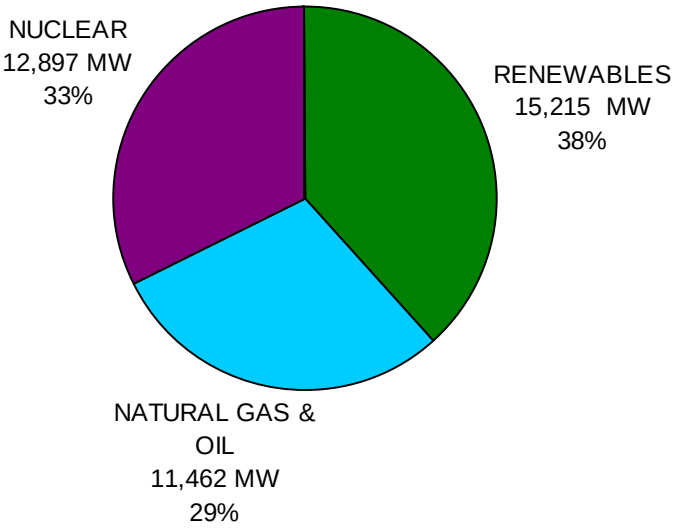
Source: OPA

Figure 2.8.48 – Portfolio 5B, Energy



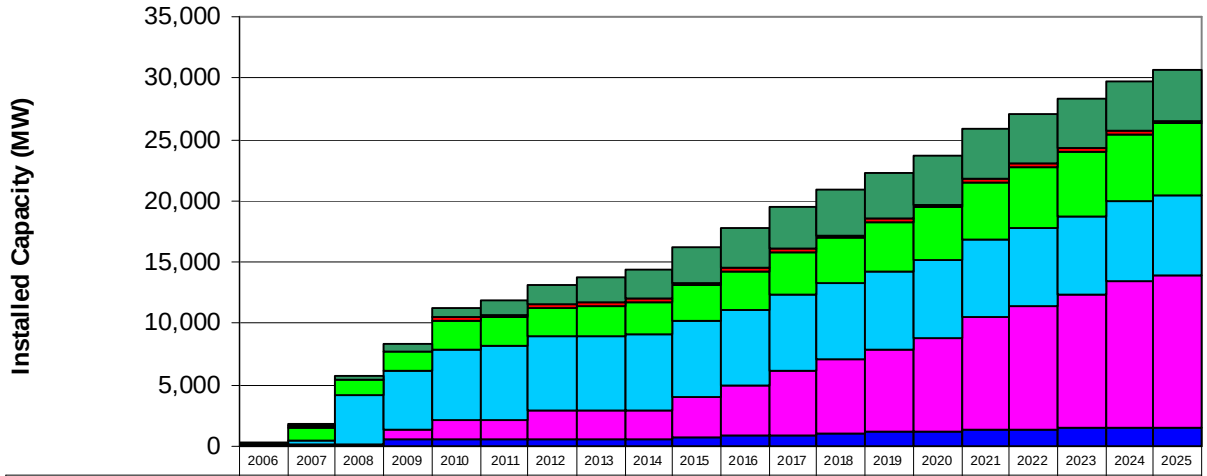
Source: OPA

Figure 2.8.49 – Portfolio 5B: Composition at 2025 (Installed)



Source: OPA

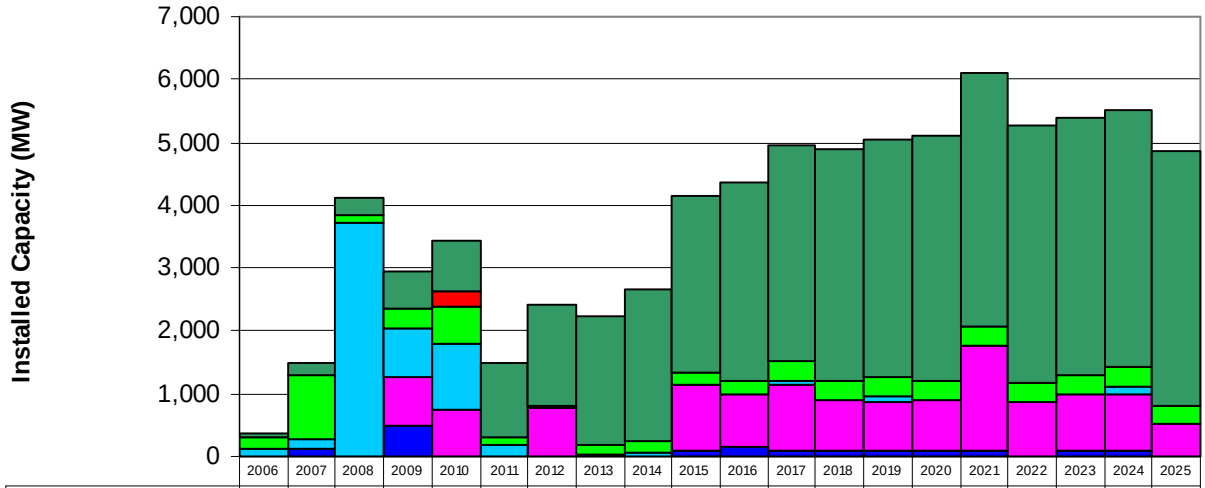
Table 2.8.46 – Portfolio 5B: Cumulative Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	206	1,233	1,340	1,645	2,245	2,345	2,350	2,500	2,700	2,900	3,100	3,400	3,700	4,000	4,300	4,610	4,920	5,230	5,530	5,830
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	117	272	3,992	4,786	5,826	6,026	6,066	6,106	6,166	6,166	6,166	6,246	6,246	6,346	6,346	6,346	6,346	6,346	6,486	6,486
New and/or Refurbished Nuclear	0	0	0	750	1,500	1,500	2,270	2,270	2,270	3,302	4,150	5,182	5,979	6,749	7,546	9,224	10,105	10,986	11,867	12,382
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	121	121	629	629	629	629	629	629	729	879	979	1,079	1,179	1,279	1,379	1,379	1,479	1,579	1,579

Source: OPA

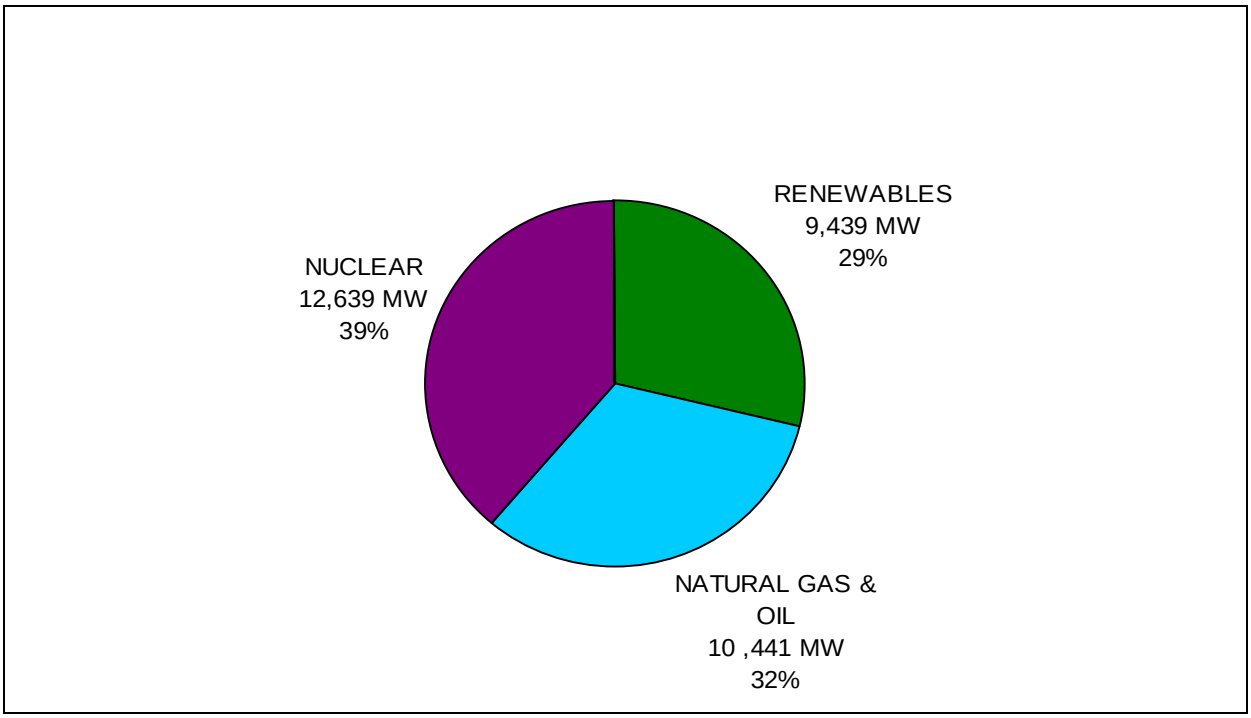
Table 2.8.47 – Portfolio 5B: New Annual Capacity (Installed)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	206	1,027	108	305	600	100	5	150	200	200	200	300	300	300	300	310	310	310	300	300
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas& Oil	117	155	3,720	794	1,040	200	40	40	60	0	0	80	0	100	0	0	0	0	140	0
Newand/or Refurbished Nuclear	0	0	0	750	750	0	770	0	0	1,032	848	1,032	797	770	797	1,678	881	881	881	515
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NewWater Power	0	121	0	508	0	0	0	0	0	100	150	100	100	100	100	100	0	100	100	0

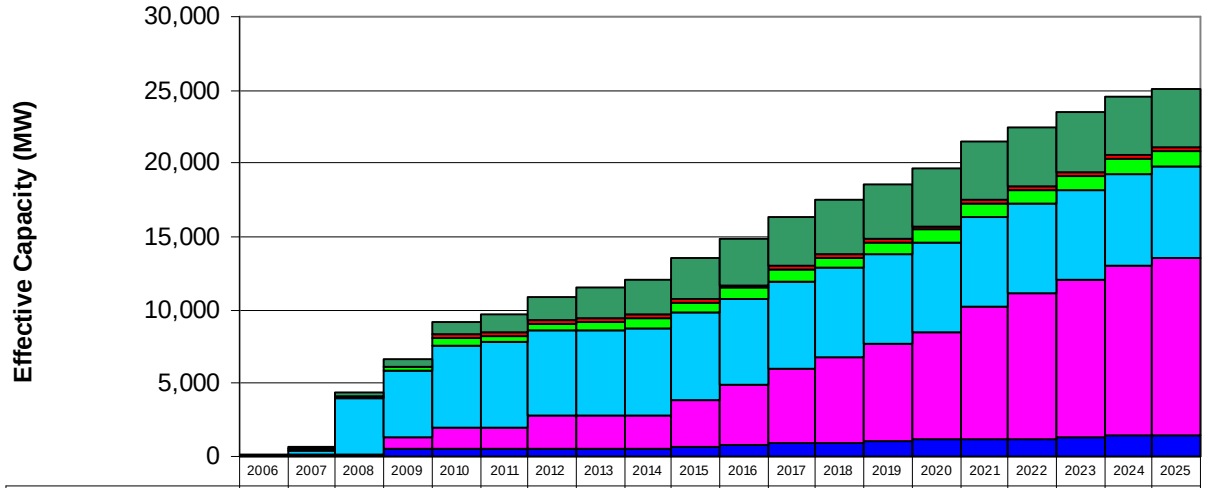
Source: OPA

Figure 2.8.50 – Portfolio 5B: Composition at 2025 (Effective)



Source: OPA

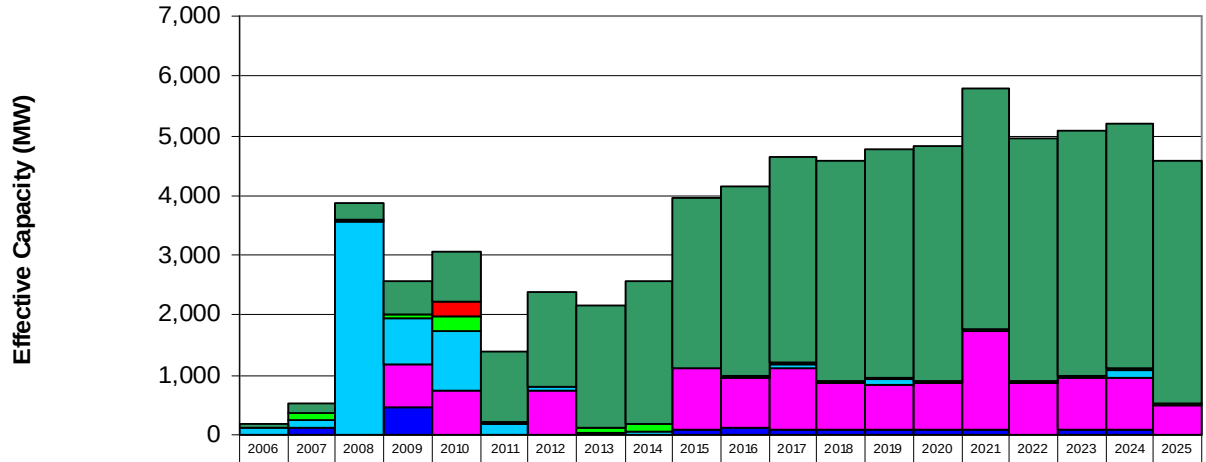
Table 2.8.48 – Portfolio 5B: Cumulative New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	10	10	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260	260
Other Renewables	21	123	138	183	443	453	458	548	668	688	708	738	768	798	828	868	908	948	978	1,008
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	261	3,832	4,595	5,593	5,785	5,823	5,862	5,919	5,919	5,919	5,996	5,996	6,092	6,092	6,092	6,092	6,092	6,227	6,227
New and/or Refurbished Nuclear	0	0	0	735	1,470	1,470	2,225	2,225	2,225	3,236	4,067	5,078	5,859	6,614	7,395	9,040	9,903	10,766	11,630	12,134
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	108	566	566	566	566	566	566	656	791	881	971	1,061	1,151	1,241	1,241	1,331	1,421	1,421

Source: OPA

Table 2.8.49 – Portfolio 5B: New Annual Capacity (Effective)



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	48	165	295	584	810	1,184	1,599	2,040	2,398	2,828	3,178	3,430	3,685	3,792	3,916	4,005	4,063	4,091	4,087	4,060
Demand Response	0	10	0	0	250	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Renewables	21	103	15	45	260	10	5	90	120	20	20	30	30	30	30	40	40	40	30	30
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas & Oil	112	149	3,571	762	998	192	38	38	58	0	0	77	0	96	0	0	0	0	134	0
New and/or Refurbished Nuclear	0	0	0	735	735	0	755	0	0	1,011	831	1,011	781	755	781	1,644	863	863	863	505
Hydro Import	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Water Power	0	108	0	457	0	0	0	0	0	90	135	90	90	90	90	90	0	90	90	0

Source: OPA

Table 2.8.50 – Portfolio 5B: Capacity at 2010, 2015, 2020, and 2025

5B Effective Capacity (MW)	2010	2015	2020	2025
CDM	1,181	3,515	4,881	5,051
Renewables	8,019	8,354	8,989	9,439
Natural Gas & Oil	9,808	10,134	10,307	10,441
Gasification	0	0	0	0
Nuclear	11,884	10,797	10,131	12,639
Coal	0	0	0	0
Total	30,893	32,800	34,308	37,570
5B Installed Capacity (MW)	**2010**	**2015**	**2020**	**2025**
CDM	1,181	3,515	4,881	5,051
Renewables	10,680	11,435	13,385	15,215
Natural Gas & Oil	10,802	11,142	11,322	11,462
Gasification	0	0	0	0
Nuclear	12,127	11,017	10,338	12,897
Coal	0	0	0	0
Total	34,791	37,110	39,927	44,625

Source: OPA

2.8.5. Comparison of Portfolios

The portfolios described above illustrate a number of potential responses to a number of potential scenarios over the next 20 years. The following paragraphs briefly compare and contrast the 10 portfolios and highlight the types of insights they help illustrate. Table 2.8.51 summarizes the portfolios, underscoring key differences. Tables 2.8.52 – 2.8.71 provide cumulative annual summaries for each of the portfolios, both in installed and effective terms.

Most of the portfolios contain the common elements outlined in section 2.8.4. Portfolio 1A contains all of these elements, refurbishes or replaces almost all of Ontario's existing nuclear fleet, and sees all coal removed from service and replaced by 2009. Portfolio 1B also contains each of the common elements, and assumes the planned retirement and replacement of Ontario's coal fleet. However, Portfolio 1B does not refurbish or replace most of Ontario's nuclear fleet. Instead, it sees the retirement of almost all of Ontario's nuclear resources, and adds large new amounts of natural gas-fired generation and gasification to fill in the resulting resource gap.

While Portfolio 2A contains most of the common elements, it sees a lower materialization of out-of-province purchases as well as new natural gas-fired procurements and hydroelectric, biomass, and fuel cell resources. Portfolio 2A adds some new natural gas-fired generation and 3,000 MW of additional nuclear capacity. Portfolio 2B is similar to Portfolio 2A, except that it does not add any additional nuclear capacity but, instead, adds 2,900 MW of new natural gas-fired resources.

Portfolio 3A sees the delayed replacement of some of Ontario's coal-fired units. Because Portfolio 3A assumes the delay is anticipated and planned for, it adds emission controls on two of the units, sees fewer procurement-based natural gas-fired additions, and defers the introduction of approximately 600 MW of natural gas-fired procurements. Portfolio 3A then adds 2,000 MW of additional nuclear capacity. Portfolio 3B is similar to Portfolio 3A, in that it also sees the delayed replacement of some of the coal-fired units. However, in contrast to Portfolio 3A, Portfolio 3B assumes the delay is not anticipated and not planned for, and therefore does not add any additional emission controls, maintains all of the natural gas-fired procurements, and does not add any new nuclear capacity.

Portfolio 4A assumes a higher load growth than Portfolios 1A/B through 3A/B, as well as a higher contribution from conservation and demand management. While it contains most of the common elements except gasification, and sees all of Ontario's coal-fired capacity retired and replaced by 2009, Portfolio 4A adds 1,000 MW of new natural gas-fired capacity and 3,000 MW of additional nuclear capacity. Portfolio 4B is similar to Portfolio 4A, except that it does not add any additional nuclear capacity. Instead, it adds 2,400 MW of new natural gas-fired capacity as well as 1,000 MW of gasification.

Portfolio 5A assumes higher success in conservation and demand management potential, and that the potential is recognized now. While it contains most of the common elements, it does not include any out-of-province purchases, nor does it include approximately 200 MW of natural gas-fired procurements. Further, Portfolio 5A defers approximately 1,400 MW of the natural gas-fired procurements until later in the study period. In contrast, Portfolio 5B – which also sees higher success in conservation and demand management – does not recognize the potential until 3 years from now, and therefore does not reduce any of the common elements other than gasification and out of province purchases.

Portfolios 1A and 1B illustrate the value of maintaining the option of refurbishing or replacing Ontario's existing nuclear fleet to meet base-load requirements rather than meeting those requirements with natural gas-fired generation and gasification. Portfolios 2A and 2B illustrate circumstances which see additional requirements resulting from fewer resources materializing. Portfolios 2A and 2B illustrate two ways of meeting those additional requirements.

Portfolios 3A and 3B illustrate the value of flexibility in the short term to reduce and defer natural gas-fired capacity in face of an unavoidable delay in the shut-down of some of Ontario's coal-fired capacity. Portfolios 3A and 3B also illustrate the impact of recognizing an unavoidable delay early and factoring it into planning. Portfolios 4A and 4B illustrate the value of maintaining sufficient options to meet increasing requirements arising from higher load growth or increased reserve margins. Portfolios 5A and 5B illustrate the value of flexibility to reduce and defer natural gas-fired capacity as well as out-of-province purchases in response to higher success in capturing conservation and demand management potential. Portfolios 5A and 5B also illustrate the impact of early recognition of higher success in conservation and demand management potential.

Table 2.8.51 – Comparison of Portfolios

	PORTFOLIO (All Numbers in Nominal MW)									
	1A	**1B**	**2A**	**2B**	**3A**	**3B**	**4A**	**4B**	**5A**	**5B**
Contains all Common Elements	Yes	Yes	Less 1,200 firm purchase, half of expected new hydro, biomass, fuel cell	Less 1,200 firm purchase, half of expected new hydro, biomass, fuel cell	Nanticoke retirement delayed	Nanticoke retirement delayed	Higher load growth, more CDM, No gasification	Higher load growth, more CDM	More CDM, less 1,200 firm purchase, No gasification	More CDM, less 1,200 firm purchase, No gasification
All Procurements & on Time	Yes	Yes	Less 1,000 gas procurement	Delay 1,000 gas procurement	Less 2,000 gas procurements, 600 gas procurements deferred	Yes	Yes	Yes	Less 200 gas procurements, 1,400 gas procurements deferred	Yes
Nuclear Refurbishment /Replacement	Yes	Only Bruce A	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Additional Nuclear	No	No	3,000	No	2,000	No	3,000	No	No	No
Other New Resources	1,000 natural gas	9,300 natural gas, 750 gasification	1,300MW natural gas	3,100 natural gas	750 natural gas	1,000 natural gas	1,200 natural gas	2,400 natural gas, 1,000 gasification	No	No
Total Natural Gas/Oil Capacity by 2025	12,500	20,762	11,500	14,300	10,200	12,500	12,700	14,800	11,300	11,500
Total Nuclear Capacity by 2025	12,900	3,555	15,900	12,900	14,900	12,900	15,900	12,900	12,900	12,900
Total Renewable Capacity by 2025	16,500	14,347	14,200	14,200	16,500	16,500	16,500	16,500	15,200	15,200

Source: OPA

Table 2.8.52 – Portfolio 1A, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	7031	7242	7257	7759	8019	8029	8034	8124	8244	9604	9759	9879	9999	10119	10239	10369	10409	10539	10659	10689
Natural Gas & Oil	4327	4476	8047	8809	9808	10000	10038	10076	10134	10134	10374	10691	10931	11267	11267	11267	11267	11267	11401	11401
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	11103	10214	10131	10912	10912	11271	12134	12639
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28910	29222	30094	29682	31262	31619	32578	31770	31126	32608	33184	33968	34594	34157	34166	35043	35051	35500	36580	37068

Source: OPA

Table 2.8.53 – Portfolio 1B, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	7031	7242	7257	7759	8019	8029	8034	8124	8244	9604	9759	9879	9999	10119	10239	10279	10409	10539	10659	10689
Natural Gas & Oil	4327	4476	8047	8809	9808	10000	10038	10076	10134	10374	11574	12131	13379	14819	16403	16883	17977	18937	18937	19369
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	240	240	480	480	720	720	720
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	9785	9004	8250	7469	6579	5715	4852	3989	3484	3484	3484
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28910	29222	30094	29682	31262	31619	32578	31770	31126	31837	32542	32554	33168	34074	34886	34748	35078	35864	35946	36361

Source: OPA

Table 2.8.54 – Portfolio 2A, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	7031	7242	7257	7759	8019	8029	8034	8034	8124	8234	8254	8284	8314	8344	8374	8414	8454	8584	8614	8644
Natural Gas & Oil	4327	4476	8047	8809	8809	9001	9001	9337	10009	10009	10249	10249	10249	10249	10249	10249	10345	10345	10480	10480
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	12083	13063	13154	13071	13852	13852	14211	15074	15579
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28910	29222	30094	29682	30264	30620	31542	30941	31122	31353	31794	33151	34188	34304	34223	35010	35115	35564	36553	37041

Source: OPA

Table 2.8.55 – Portfolio 2B, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	7031	7242	7257	7759	8019	8029	8034	8034	8034	8144	8164	8194	8224	8344	8374	8414	8454	8584	8614	8644
Natural Gas & Oil	4327	4476	8047	8809	8809	9001	9001	9001	10057	10537	10537	11497	12457	12457	12937	12937	13033	13033	13168	13168
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	11103	10214	10131	10912	10912	11271	12134	12639
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28910	29222	30094	29682	30264	30620	31542	30605	31080	31791	31992	33329	34346	33572	33971	34758	34863	35312	36301	36789

Source: OPA

Table 2.8.56 – Portfolio 3A, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	7031	7242	7257	7759	8019	8029	8034	8214	8604	10009	10119	10239	10359	10479	10509	10549	10589	10629	10659	10689
Natural Gas & Oil	4327	4476	6525	7288	7326	7518	7988	8459	9179	9179	9179	9179	9256	9256	9256	9256	9256	9256	9256	9256
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	12083	12174	12091	12872	12872	13231	14094	14599
Coal	6112	5767	3276	3282	3748	2351	1420	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28910	29222	29055	31442	32529	31488	31949	30242	30771	32298	32589	33056	34259	34465	34384	35172	35180	35539	36394	36882

Source: OPA

Table 2.8.57 – Portfolio 3B, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	7031	7242	7257	7489	7839	7849	7854	8034	8124	9604	9759	9879	9999	10119	10239	10279	10409	10539	10659	10689
Natural Gas & Oil	4327	4476	8047	8809	9808	10000	10038	10076	10134	10134	10134	10451	10691	10931	11171	11171	11267	11267	11401	11401
Gasification	0	0	0	0	0	0	0	0	240	240	240	240	240	240	240	240	240	240	240	240
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	11103	10214	10131	10912	10912	11271	12134	12639
Coal	6112	5767	3748	3748	3748	2351	1420	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28910	29222	31049	33160	34830	33790	33819	31680	31246	32848	33184	33968	34354	33821	34070	34857	35051	35500	36580	37068

Source: OPA

Table 2.8.58 – Portfolio 4A, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1182	1606	2080	2591	3013	3527	3971	4313	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	7031	7242	7257	7759	8019	8029	8034	8124	8334	9694	9849	9879	10089	10389	10419	10459	10589	10629	10659	10689
Natural Gas & Oil	4327	4476	8047	8809	9808	10000	10230	10268	10806	10806	10806	10883	11017	11113	11113	11113	11113	11113	11113	11593
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	12083	12174	12091	12872	13852	14211	15074	15579
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28696	28853	29615	29152	30893	31520	32983	32611	32950	34824	35473	36178	37798	38411	38505	39430	40609	41040	41930	42912

Source: OPA

Table 2.8.59 – Portfolio 4B, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1182	1606	2080	2591	3013	3527	3971	4313	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	7031	7242	7257	7759	8019	8029	8034	8124	8424	9784	9939	9969	10089	10299	10329	10369	10409	10539	10659	10689
Natural Gas & Oil	4327	4476	8047	9145	10144	10336	10374	10412	10710	10710	10710	10787	11891	12035	12851	12851	13427	13427	13561	13657
Gasification	0	0	0	0	0	0	0	0	0	240	240	240	240	480	480	720	720	960	960	960
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	11103	10214	10131	10912	10912	11271	12134	12639
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28696	28853	29615	29488	31229	31856	33127	32755	32944	35058	35707	36412	37932	37763	38672	39838	40522	41284	42398	42996

Source: OPA

Table 2.8.60 – Portfolio 5A, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1181	1606	2080	2589	3012	3515	3947	4273	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	7031	7242	7257	7759	8019	8029	8034	8124	8244	8354	8509	8629	8749	8869	8989	9029	9159	9289	9409	9439
Natural Gas & Oil	4327	4476	7500	8454	8492	8684	8723	8761	8819	8819	8819	8896	9635	10019	10019	10019	10115	10115	10249	10249
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	11103	10214	10131	10912	10912	11271	12134	12639
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28696	28853	29068	28796	29577	30204	31476	31102	30872	31485	32122	32901	34096	33837	34020	34946	35240	35762	36876	37378

Source: OPA

Table 2.8.61 – Portfolio 5B, Cumulative Annual Capacity – Effective

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1181	1606	2080	2589	3012	3515	3947	4273	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	7031	7242	7257	7759	8019	8029	8034	8124	8244	8354	8509	8629	8749	8869	8989	9119	9159	9289	9409	9439
Natural Gas & Oil	4327	4476	8047	8809	9808	10000	10038	10076	10134	10134	10134	10211	10211	10307	10307	10307	10307	10307	10441	10441
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	11169	11169	11169	11904	11884	11884	12639	11628	10797	10797	10847	11103	11103	10214	10131	10912	10912	11271	12134	12639
Coal	6112	5767	2793	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	28696	28853	29615	29152	30893	31519	32791	32418	32187	32800	33437	34216	34672	34125	34308	35324	35432	35954	37068	37570

Source: OPA

Table 2.8.62 – Portfolio 1A, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	8013	9160	9267	10080	10680	10780	10785	10935	11135	12685	13035	13435	13835	14235	14635	15045	15355	15765	16165	16465
Natural Gas & Oil	5093	5248	8968	9762	10802	11002	11042	11082	11142	11142	11392	11722	11972	12322	12322	12322	12322	12322	12462	12462
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	11330	10422	10338	11135	11135	11501	12382	12897
Coal	6434	6070	2940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31207	32443	33401	33199	35161	35615	36592	35824	35246	36918	37700	38782	39708	39547	39834	41007	41286	42022	43405	44173

Source: OPA [A]

Table 2.8.63 – Portfolio 1B, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1,209	1,551	1,706	1,867	1,942	1,952	2,073	2,204	2,294	2,321	2,317	2,288	2,254	2,223	2,183	2,145	2,098
Renewables	8,013	9,160	9,267	10,080	10,680	10,780	10,785	10,935	11,135	12,685	13,035	13,435	13,835	14,235	14,635	14,945	15,355	15,765	16,165	16,465
Natural Gas & Oil	5,093	5,248	8,968	9,762	10,802	11,002	11,042	11,082	11,142	11,392	12,142	13,222	14,522	16,022	17,672	18,172	19,312	20,312	20,312	20,762
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	250	250	500	500	750	750	750
Nuclear	11,397	11,397	11,397	12,147	12,127	12,127	12,897	11,865	11,017	9,985	9,188	8,418	7,621	6,713	5,832	4,951	4,070	3,555	3,555	3,555
Coal	6,434	6,070	2,940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31,207	32,443	33,401	33,199	35,161	35,615	36,592	35,824	35,246	36,136	36,570	37,370	38,299	39,538	40,678	40,823	41,461	42,566	42,928	43,631

Source: OPA

Table 2.8.64 – Portfolio 2A, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	8013	9160	9267	10080	10680	10780	10785	10785	10885	11185	11385	11685	11985	12285	12585	12895	13205	13615	13915	14215
Natural Gas & Oil	5093	5248	8968	9762	9762	9962	9962	10312	11012	11012	11262	11262	11262	11262	11262	11262	11362	11362	11502	11502
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	12330	13330	13422	13338	14135	14135	14501	15382	15897
Coal	6434	6070	2940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31207	32443	33401	33199	34121	34575	35512	34904	35116	35538	36170	37822	39148	39537	39724	40797	41176	41912	43195	43963

Source: OPA

Table 2.8.65 – Portfolio 2B, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	8013	9160	9267	10080	10680	10780	10785	10785	10785	11085	11285	11585	11885	12285	12585	12895	13205	13615	13915	14215
Natural Gas & Oil	5093	5248	8968	9762	9762	9962	9962	9962	11062	11562	11562	12562	13562	13562	14062	14062	14162	14162	14302	14302
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	11330	10422	10338	11135	11135	11501	12382	12897
Coal	6434	6070	2940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31207	32443	33401	33199	34121	34575	35512	34554	35066	35988	36370	38022	39348	38837	39524	40597	40976	41712	42995	43763

Source: OPA

Table 2.8.66 – Portfolio 3A, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	8013	9160	9267	10080	10680	10780	10785	11035	11535	13135	13435	13835	14235	14635	14935	15245	15555	15865	16165	16465
Natural Gas & Oil	5093	5248	7383	8177	8217	8417	8907	9397	10147	10147	10147	10147	10227	10227	10227	10227	10227	10227	10227	10227
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	12330	12422	12338	13135	13135	13501	14382	14897
Coal	6434	6070	3448	3455	3945	2475	1495	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31207	32443	32324	35069	36521	35505	35952	34239	34901	36623	37105	37857	39363	39852	40039	41112	41391	42027	43170	43938

Source: OPA

Table 2.8.67 – Portfolio 3B, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	270	568	828	1209	1551	1706	1867	1942	1952	2073	2204	2294	2321	2317	2288	2254	2223	2183	2145	2098
Renewables	8013	9160	9267	9780	10480	10580	10585	10835	10935	12685	13035	13435	13835	14235	14635	14945	15355	15765	16165	16465
Natural Gas & Oil	5093	5248	8968	9762	10802	11002	11042	11082	11142	11142	11142	11472	11722	11972	12222	12222	12322	12322	12462	12462
Gasification	0	0	0	0	0	0	0	0	250	250	250	250	250	250	250	250	250	250	250	250
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	11330	10422	10338	11135	11135	11501	12382	12897
Coal	6434	6070	3945	3945	3945	2475	1495	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	31207	32443	34406	36844	38906	37890	37887	35724	35296	37168	37700	38782	39458	39197	39734	40807	41286	42022	43405	44173

Source: OPA

Table 2.8.68 – Portfolio 4A, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1182	1606	2080	2591	3013	3527	3971	4313	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	8013	9160	9267	10080	10680	10780	10785	10935	11235	12785	13135	13435	13935	14535	14835	15145	15555	15865	16165	16465
Natural Gas & Oil	5093	5248	8968	9762	10802	11002	11242	11282	11842	11842	11842	11922	12062	12162	12162	12162	12162	12162	12162	12662
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	12330	12422	12338	13135	14135	14501	15382	15897
Coal	6434	6070	2940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	30993	32074	32922	32669	34791	35516	37004	36673	37107	39172	40017	41000	42936	43854	44217	45428	46906	47616	48793	50075

Source: OPA

Table 2.8.69 – Portfolio 4B, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1182	1606	2080	2591	3013	3527	3971	4313	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	8013	9160	9267	10080	10680	10780	10785	10935	11335	12885	13235	13535	13935	14435	14735	15045	15355	15765	16165	16465
Natural Gas & Oil	5093	5248	8968	10112	11152	11352	11392	11432	11742	11742	11742	11822	12972	13122	13972	13972	14572	14572	14712	14812
Gasification	0	0	0	0	0	0	0	0	0	250	250	250	250	500	500	750	750	1000	1000	1000
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	11330	10422	10338	11135	11135	11501	12382	12897
Coal	6434	6070	2940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	30993	32074	32922	33019	35141	35866	37154	36823	37107	39422	40267	41250	43096	43214	44427	45888	46866	47926	49343	50225

Source: OPA

Table 2.8.70 – Portfolio 5A, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1181	1606	2080	2589	3012	3515	3947	4273	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	8013	9160	9267	10080	10680	10780	10785	10935	11135	11435	11785	12185	12585	12985	13385	13695	14105	14515	14915	15215
Natural Gas & Oil	5093	5248	8398	9392	9432	9632	9672	9712	9772	9772	9772	9852	10622	11022	11022	11022	11122	11122	11262	11262
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	11330	10422	10338	11135	11135	11501	12382	12897
Coal	6434	6070	2940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	30993	32074	32352	32299	33421	34146	35434	35102	34937	35740	36572	37640	39146	39164	39627	40838	41416	42226	43643	44425

Source: OPA

Table 2.8.71 – Portfolio 5B, Cumulative Annual Capacity – Installed

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
CDM	56	199	349	679	1181	1606	2080	2589	3012	3515	3947	4273	4608	4735	4881	4985	5054	5087	5083	5051
Renewables	8013	9160	9267	10080	10680	10780	10785	10935	11135	11435	11785	12185	12585	12985	13385	13795	14105	14515	14915	15215
Natural Gas & Oil	5093	5248	8968	9762	10802	11002	11042	11082	11142	11142	11142	11222	11222	11322	11322	11322	11322	11322	11462	11462
Gasification	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	11397	11397	11397	12147	12127	12127	12897	11865	11017	11017	11068	11330	11330	10422	10338	11135	11135	11501	12382	12897
Coal	6434	6070	2940	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	30993	32074	32922	32669	34791	35516	36804	36472	36307	37110	37942	39010	39746	39464	39927	41238	41616	42426	43843	44625

Source: OPA

2.9 Analysis Results

In this Part, the results of the environmental, cost and risk analyses are presented for each of the scenarios OPA has examined.

2.9.1 Key Findings

- Early recognition of changes in assumptions, such as greater success in capturing conservation or delayed coal replacement, has advantages,
- A robust portfolio should enable adaptation to take advantage of evolving trends.
- The portfolios tend to show similar environmental impacts and costs, as they share many common elements.
- Environmental impacts are greatest where there is greater use of fossil fuel-based resources.
- Greatest cost-related differences relate to risk around costs.
- The main driver of higher risk is natural gas price variability; portfolios with greater reliance on natural gas tend to exhibit higher risk.
- In general, portfolios that use less fossil fuel resources present lower costs and environmental impacts and are less exposed to risk; these portfolios are more robust, performing better under different possible futures except under a future with low gas prices.

2.9.2 Introduction

As described in Part 2.8 OPA reviewed two alternative responses with alternative portfolios for each scenario. Deterministic and stochastic sensitivity studies were then run for each portfolio to assess environmental impacts and scores, costs and risks. For reference purposes, the scenarios below are matched to the descriptions used in Part 1.2, and are outlined in Table 2.9.1 below.

Table 2.9.1 – Scenarios and Descriptions

Scenario 1	Planning Assumptions
Scenario 2	Low Renewables
Scenario 3	Delayed Coal Replacement
Scenario 4	High Demand
Scenario 5	High Conservation

Source: OPA

From here, the environmental impacts and scores were first derived (as described Part 2.6). The revenues and cash flows were then determined using the Portfolio Screening Model (PSM) and were discounted at 5% (The rationale for using this perspective on costs is explained in Part 1.2. An overview of the PSM can be found in Part 4.1 – Navigant Report).

The terminal values of the scenarios, i.e. values of cash flows beyond 2025, are included in the analysis and labeled "long term" in the figures. Risk around costs is also calculated. Risks were assessed through Monte Carlo simulations with the PSM. Sensitivity analyses were also applied to examine the robustness of the Portfolios.

2.9.3 Scenario 1 (Planning Assumptions)

2.9.3.1 Environmental Impacts

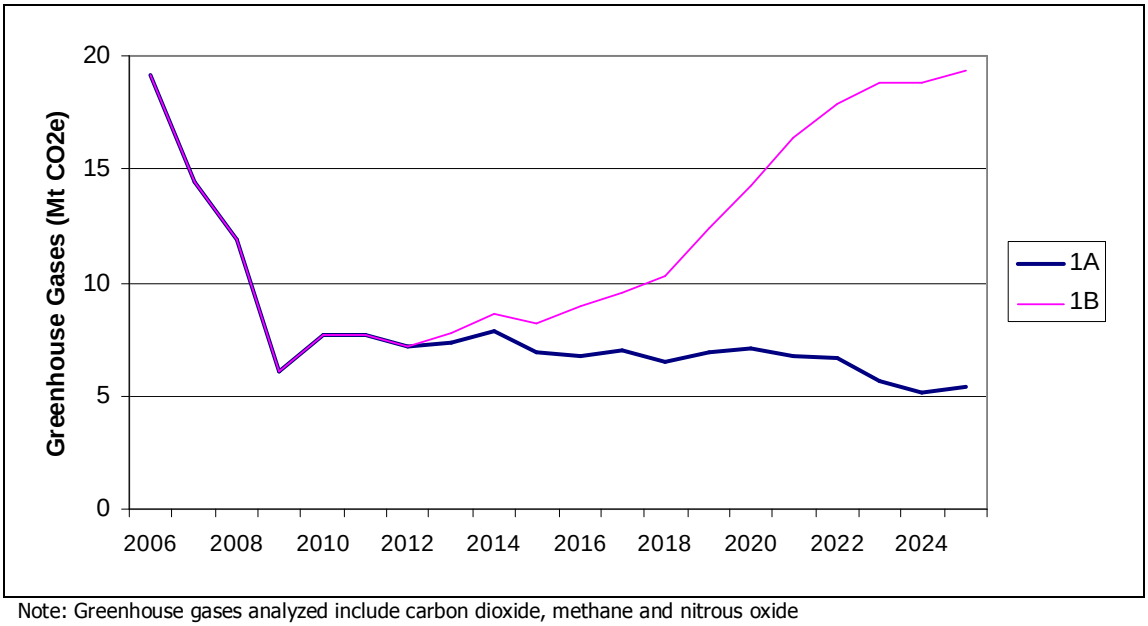
The annual greenhouse gas emissions over the study period for Portfolios 1A and 1B , described in Part 2.8, are shown in Figure 2.9.1. Greenhouse gases analyzed are carbon dioxide, methane, and nitrous oxide and are expressed below for comparison purposes in terms of carbon dioxide equivalent, or CO_2e.

Figure 2.9.1 illustrates that Portfolio 1B generates more megatons of greenhouse gases than Portfolio 1A over the study period, reflecting its larger use of fossil fuel resources. Total greenhouse gas emissions over the study period are 237Mt CO_2e for Portfolio 1A, and 333Mt CO_2e for Portfolio 1B.

The environmental loading scores of the Portfolios for both during and beyond the study period, including the breakdown of the different contributions to the score, are shown in Figure 2.9.2.

Portfolio 1B, as can be seen, has higher environmental impacts, mostly driven by the increase in carbon dioxide and contaminant emissions from the greater use of fossil-fired generation. Portfolio 1B presents however slightly lower radioactivity. The absolute values associated with each portfolio are presented in Table 2.9.2. The methodology for deriving environmental loading scores is discussed in Part 2.6.

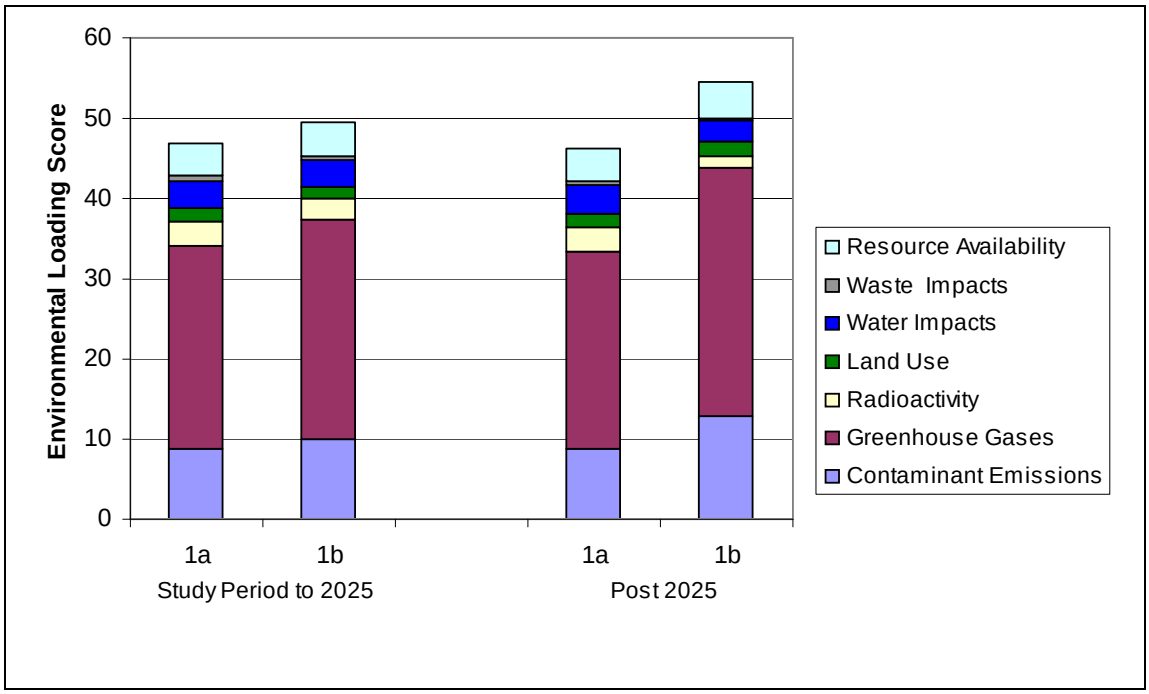
Figure 2.9.1 – Portfolios 1A and 1B – Annual Greenhouse Gas Emissions



Note: Greenhouse gases analyzed include carbon dioxide, methane and nitrous oxide

Source: OPA

Figure 2.9.2 – Portfolios 1A and 1B – Environmental Loading Scores by Impact



Source: OPA

Table 2.9.2 – Portfolios 1A and 1B - Absolute Environmental Loading Values

Indicator	Metric	Portfolio 1A	Portfolio 1B
Contaminant Emissions	kT	1032	1195
Greenhouse Gas Emissions	Mt CO2e	237	333
Radioactivity	Sv	2760	2208
Land Use	km2	1116.2	1120.4
Water Use - Withdrawal	TL	478	399
Water Use - Consumption	TL	2.95	2.5
Waste	kT	260	234

Source: OPA

2.9.3.2 Costs, Risks and Sensitivities

Describing the costs of the scenarios has many aspects. This section presents the costs from various perspectives:

1. Costs allocated to the study period (2006 – 2025) and post study period
2. Cost of capital expenditures during the study period, first "as spent" and then in present value terms
3. Detailed year-by-year expenditure on capital
4. Range of costs around the average, using the stochastic Monte Carlo technique described in section 2.6
5. Analysis of sources of cost risk
6. Range of variability attributed to different sources of risk, using what is known as a "Tornado Diagram"
7. Sensitivity analysis of the average cost to various cost factors.

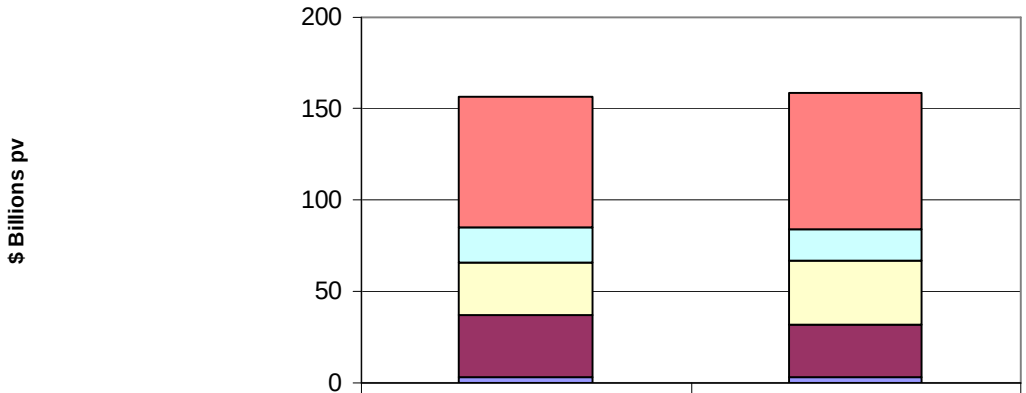
Figure 2.9.3 shows the present value and composition of cash flows for Portfolios 1A and 1B. These costs are split between the study period (2006 – 2025) and post that period. The capital cost shown are the portion to be recovered during the study period, the remainder is recovered post study period.

In total, the costs look very similar. However, in interpreting this and other cost figures throughout this Part, it should be kept in mind that many of the costs are common and are not influenced by the policy decisions being investigated. The Figure shows that Portfolio 1A is less expensive by about $2 billion under the deterministic analysis, with the slightly higher capital costs in the study period paying off in the longer term. The sensitivity and risk assessment will all be around this total cost during and post study period.

Figure 2.9.4 outlines capital expenditures for Portfolio 1A and 1B. Total capital expenditures are, respectively, $42.7 billion and $ 36.9 (present value). Table 2.9.3 details the capital expenditures as spent. These are the total capital expenditures, and are not allocated to study or post study period as shown in Figure 2.9.3. Of note, capital expenditures are identical between the portfolios from 2006 to 2013, with differences in the longer term relating to differing investment

in gas-fired and nuclear plant. Figure 2.9.5 illustrates capital expenditures, as spent, for Portfolio 1A.

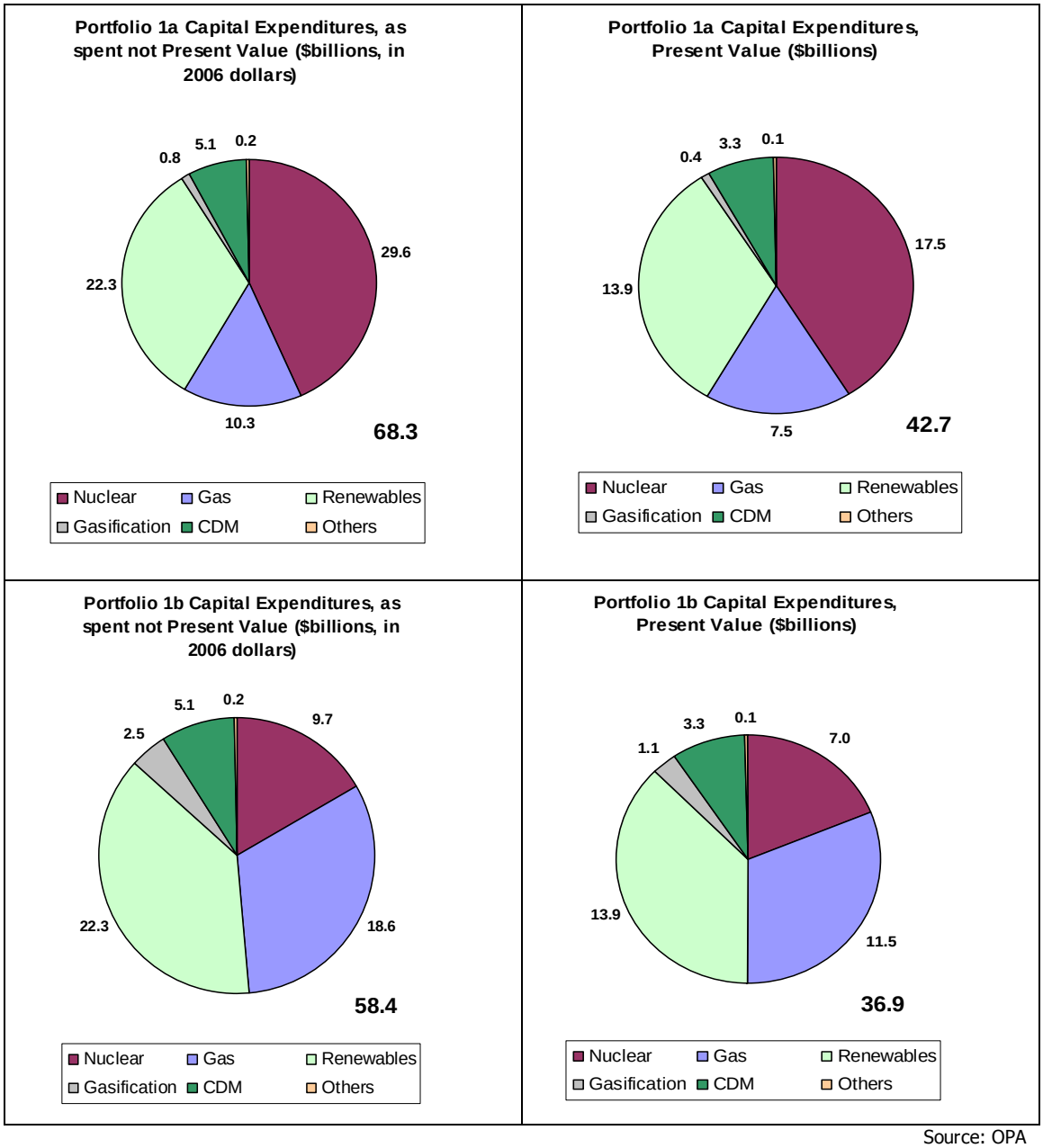
Figure 2.9.3 – Portfolios 1A and 1B – Present Value of Cash Flow Components



	1A	1B
Total	157	159
Long Term (Post 2025)	71	75
Capital Charged to Study Period	20	18
Fuel & Variable OM&A	28	35
Fixed OM&A	34	29
CDM	3	3

Source: OPA

Figure 2.9.4 – Portfolios 1A and 1B - Capital Expenditures



Source: OPA

Table 2.9.3 – Portfolios 1A and 1B – Annual Capital Expenditures, As Spent, not Present Value ($ Billions, 2006 Dollars)

Capital Expenditures 1a

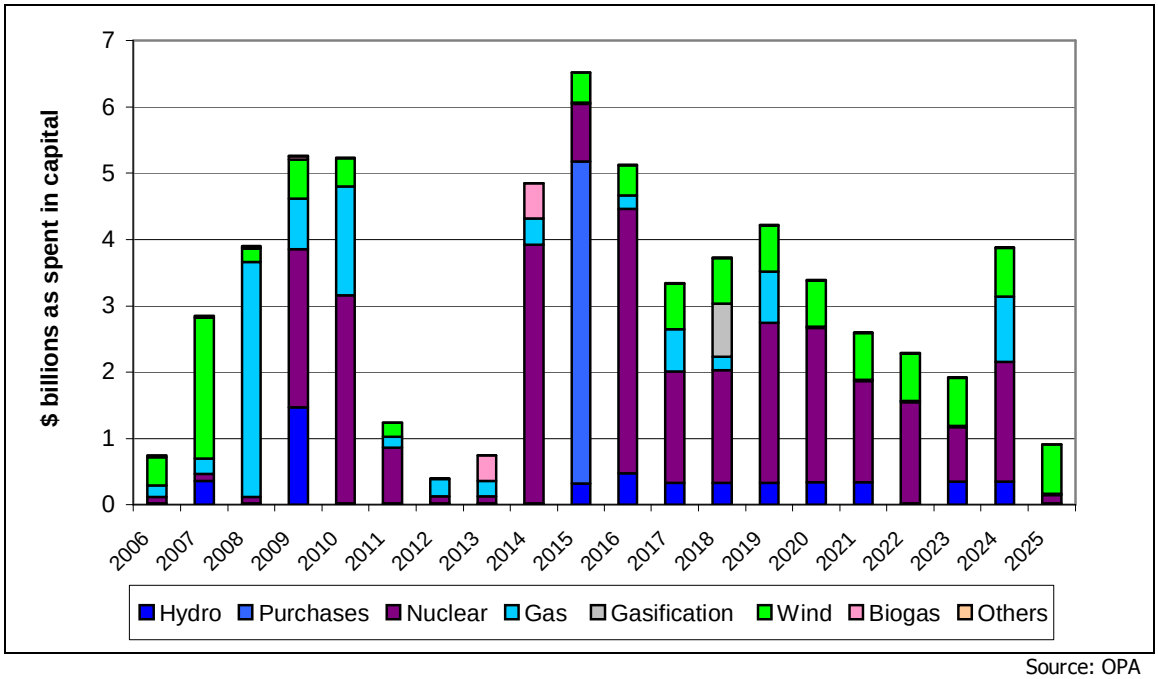
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	1.70	2.41	2.33	1.52	1.52	0.82	1.80	0.12	29.60
Gas	0.18	0.23	3.54	0.76	1.64	0.16	0.26	0.23	0.39	0.02	0.20	0.64	0.21	0.77	0.02	0.02	0.02	0.02	0.99	0.02	10.29
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.41	0.54	5.62	0.93	1.01	1.02	1.03	1.04	1.06	0.74	1.08	1.09	0.76	22.32
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.80	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.80
CDM	0.03	0.07	0.14	0.23	0.34	0.46	0.56	0.61	0.58	0.53	0.40	0.25	0.29	0.15	0.12	0.11	0.09	0.06	0.03	0.01	5.07
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.77**	**2.92**	**4.04**	**5.49**	**5.58**	**1.70**	**0.96**	**1.36**	**5.43**	**7.05**	**5.53**	**3.59**	**4.02**	**4.37**	**3.52**	**2.71**	**2.38**	**1.98**	**3.91**	**0.93**	**68.25**

Capital Expenditures 1b

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	0.11	0.11	0.11	0.90	0.91	0.12	0.12	0.12	0.08	0.08	0.09	0.09	9.75
Gas	0.18	0.23	3.54	0.76	1.64	0.16	0.26	0.23	0.39	0.20	0.70	1.34	1.61	1.57	1.70	0.55	2.03	1.09	0.02	0.38	18.57
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.41	0.54	5.62	0.93	1.01	1.02	1.03	1.04	0.73	1.07	1.08	1.09	0.76	22.32
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.81	0.00	0.82	0.00	0.84	0.00	0.00	2.47
CDM	0.03	0.07	0.14	0.23	0.34	0.46	0.56	0.61	0.58	0.53	0.40	0.25	0.29	0.15	0.12	0.11	0.09	0.06	0.03	0.01	5.07
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.77**	**2.92**	**4.04**	**5.49**	**5.58**	**1.70**	**0.96**	**1.36**	**1.63**	**6.47**	**2.16**	**3.50**	**3.83**	**3.69**	**2.99**	**2.33**	**3.27**	**3.16**	**1.23**	**1.25**	**58.36**

Source: OPA

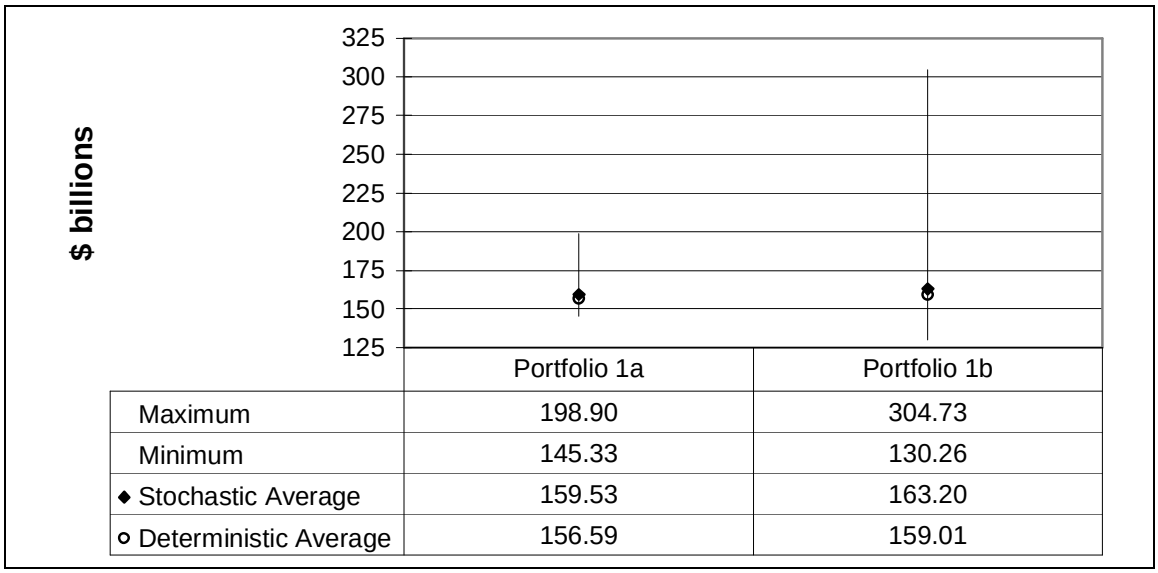
Figure 2.9.5 – Portfolio 1A - Capital Expenditures, As Spent



Source: OPA

Figure 2.9.6 below shows the stochastic and deterministic average of the cash flows of Portfolios 1A and 1B, together with the range of the spread of the results.

Figure 2.9.6 – Portfolios 1A and 1B - Present Value of Cash Flows



	Portfolio 1a	Portfolio 1b
Maximum	198.90	304.73
Minimum	145.33	130.26
◆ Stochastic Average	159.53	163.20
○ Deterministic Average	156.59	159.01

Source: OPA

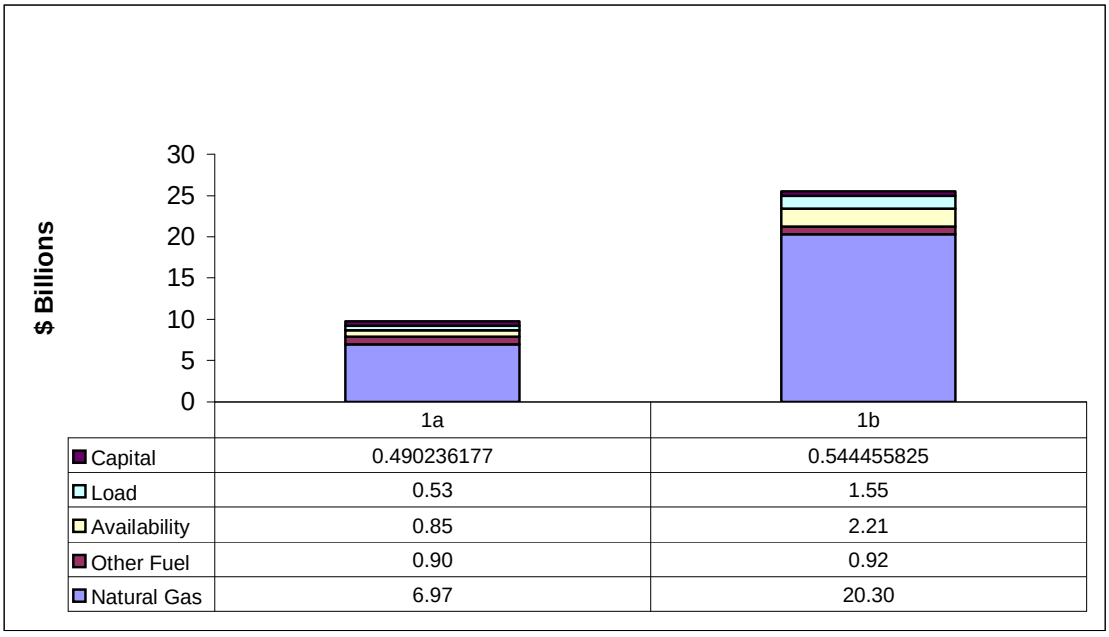
While Portfolio 1A presents an advantage of $2 billion over portfolio 1B when considering deterministic results, it presents a more apparent advantage of $4 billion when looking at the stochastic results, due to the impact that gas price volatilities have

on the cost, which is not fully captured by the deterministic simulation. Additionally, portfolio 1B has a measurably larger risk.

Figure 2.9.7 illustrates the breakdown of the contributions to the variation around costs. In both Portfolios, natural gas price volatility is the overwhelming contributor to cost risk. As Portfolio 1B relies more heavily on natural gas-fired generation, it exhibits greater variability around natural gas fuel price. The second largest contributor to price risk is availability, which reflects forced outages as well as fuel limitations on wind and hydroelectric resources.

Whereas Figure 2.9.7 illustrates the standard deviation of results, Figure 2.9.8 illustrates the stochastic minimum and maximum value, that is another way of presenting the breakdown of variation around the cost. Figure 2.9.8 shows that the cost spread of Portfolio 1B is considerably greater than that of Portfolio 1A, and is principally driven by natural gas price variability.

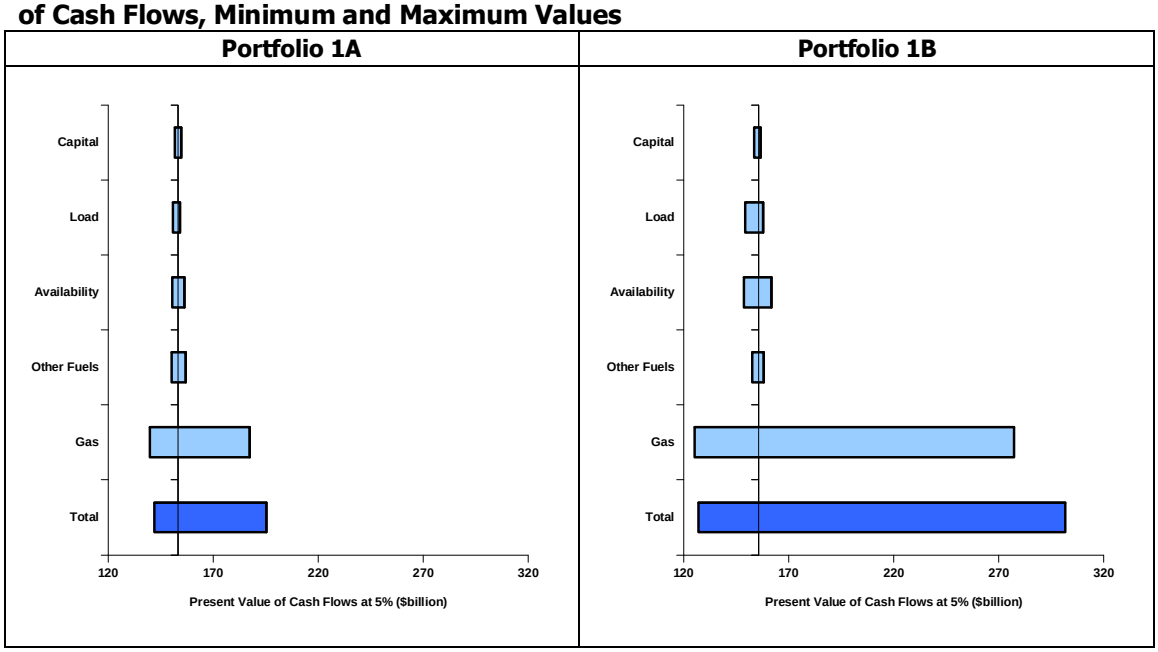
Figure 2.9.7 – Portfolios 1A and 1B - Indicative Volatility Contribution, Present Value of Cash Flows, Standard Deviation



	1a	1b
Capital	0.490236177	0.544455825
Load	0.53	1.55
Availability	0.85	2.21
Other Fuel	0.90	0.92
Natural Gas	6.97	20.30

Source: OPA

Figure 2.9.8 – Portfolios 1Aand 1B – Indicative Volatility Contribution, Present Value of Cash Flows, Minimum and Maximum Values



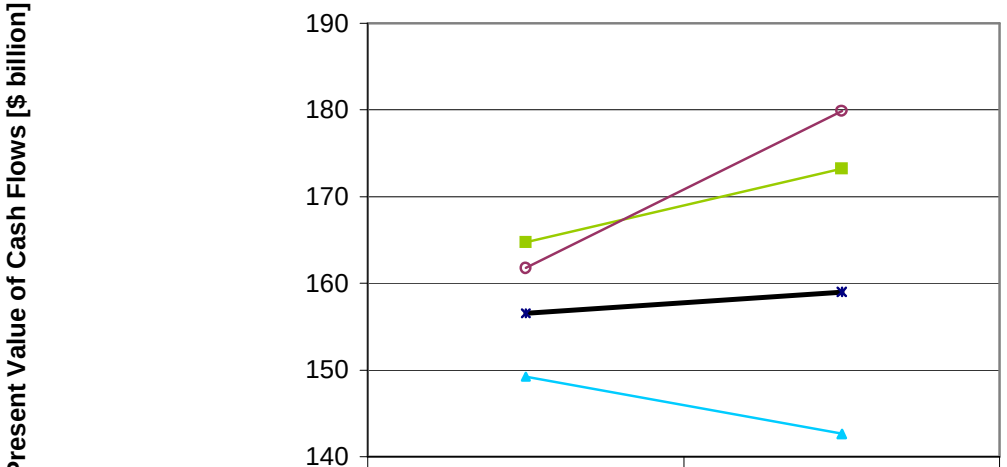
Source: OPA

Figure 2.9.9 summarizes the results of the sensitivity studies applied to the Portfolios. The climate change sensitivity assumes that global warming reduces hydrologic availability by 30%, and in which context carbon mitigation costs (of $15/ton) are applied to all carbon dioxide generated rather than only to emissions over an allowance threshold. Further, increased demand for non-greenhouse gas options increases their commercialization and reduces their costs, e.g. production incentives for wind are increased by 30%, and nuclear capital costs are decreased by 30%.

The low gas price sensitivity assumes natural gas prices fall to about $5 per MMBtu. The technology improvement sensitivity assumes a higher natural gas price and increased investments in the efficient use of natural gas as a fuel for electricity production. Accordingly, capital costs for fuel cells are reduced by 30%. Wind power costs are also reduced by 30%.

The results of the sensitivities indicate that Portfolio 1A is more robust than portfolio 1B and exhibits lower costs than 1B, except in the case of low natural gas prices in which case Portfolio 1B is less expensive.

Figure 2.9.9 – Portfolios 1A and 1B - Deterministic Sensitivity Analysis, Present Value of Cash Flows



	Portfolio 1a	Portfolio 1b
Deterministic Average	156.59	159.01
Climate change	164.75	173.26
Low Gas Price	149.26	142.66
Technology Improvement	161.77	179.87

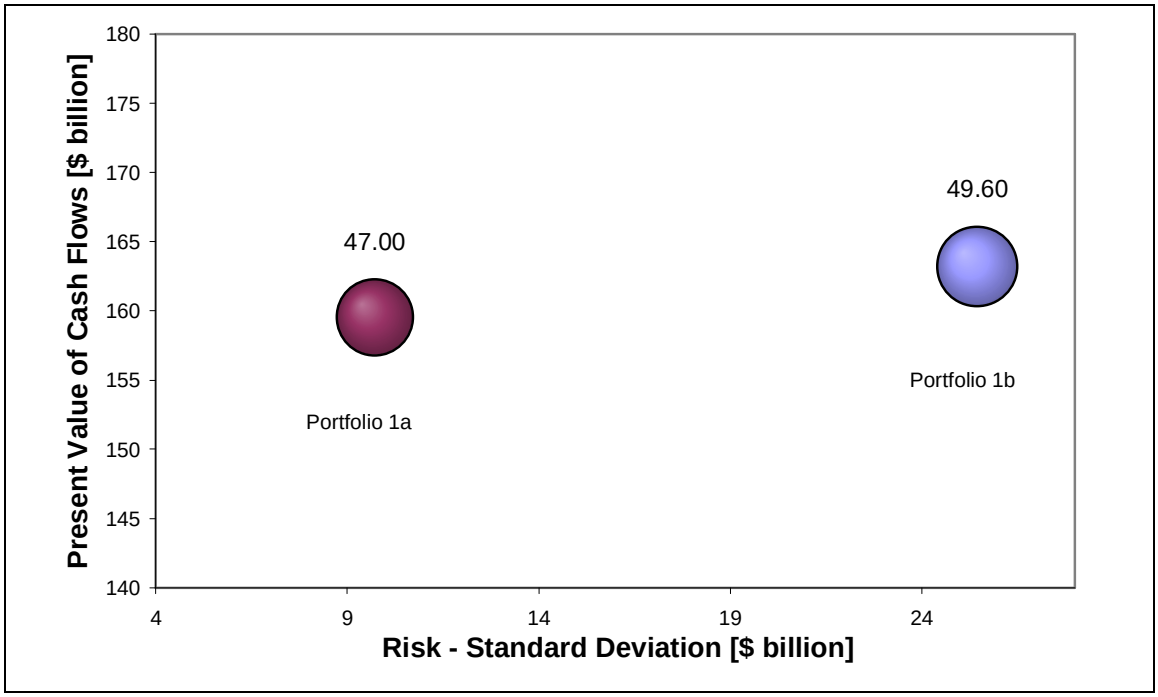
Source: OPA

2.9.3.3 Combined Cost, Risk, and Environmental Loading

Figure 2.9.10 summarizes the cost, risk and environmental loading score of Portfolios 1A and 1B. The costs reflect stochastic average costs, while the risk is measured by the standard deviation of the stochastic outcomes. The environmental indicators shown are the sums of environmental loading scores by impact. The environmental loading scores are represented as a number in the figure and by the size of the corresponding circles.

Figure 2.9.10 indicates that Portfolio 1B, which relies more heavily on natural gas-fired generation, entails higher cost, significantly more risk, and greater environmental impact than Portfolio 1A.

Figure 2.9.10 – Portfolios 1A and 1B - Cost/Risk/Environmental Loading Score



Source: OPA

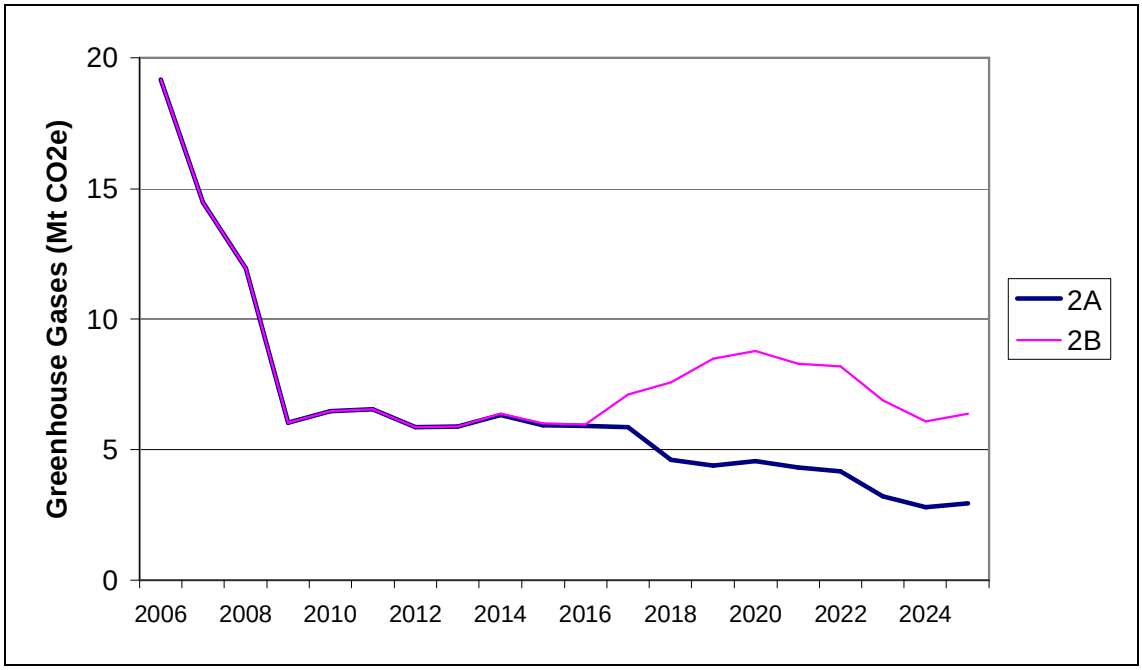
2.9.4 Scenario 2 (Low Renewables)

2.9.4.1 Environmental Impacts

The annual greenhouse gas emissions for Portfolios 2A and 2B are shown in Figure 2.9.11. As can be seen, Portfolio 2B, with its higher use of natural gas-fired generation, results in higher greenhouse gas emissions. Total greenhouse gas emissions over the study period are 201 Mt CO_2e for Portfolio 2A, and 237 MT CO_2e for Portfolio 2B.

The environmental loading scores of the Portfolios during the study period and beyond, including the breakdown of the different contributions to the score, are shown in Figure 2.9.12. The results show Portfolio 2A to have a lower environmental loading score than Portfolio 2B, and that this can be expected to be sustained in the longer-term. The absolute values associated with each portfolio are presented in Table 2.9.4.

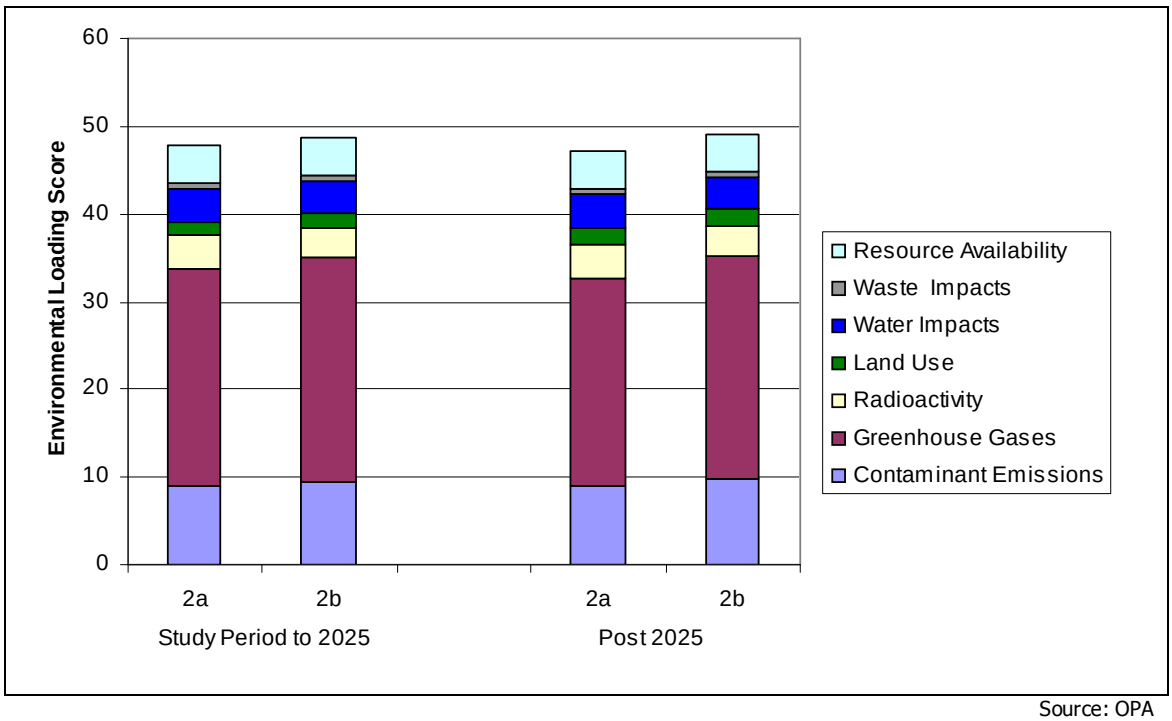
Figure 2.9.11 – Portfolios 2A and 2B - Annual Greenhouse Gas Emissions



Note: Greenhouse gases analyzed include carbon dioxide, methane and nitrous oxide

Source: OPA

Figure 2.9.12 – Portfolios 2A and 2B – Environmental Loading Scores by Impact



Source: OPA

Table 2.9.4 – Portfolios 2A and 2B - Absolute Environmental Loading Values

Indicator	Metric	Portfolio 2A	Portfolio 2B
Contaminant Emissions	kT	1004	1060
Greenhouse Gas Emissions	Mt CO2e	201	237
Radioactivity	Sv	3030	2779
Land Use	km2	1078	1074.1
Water Use – Withdrawal	TL	526	496
Water Use - Consumption	TL	3.06	2.95
Waste	kT	278	268

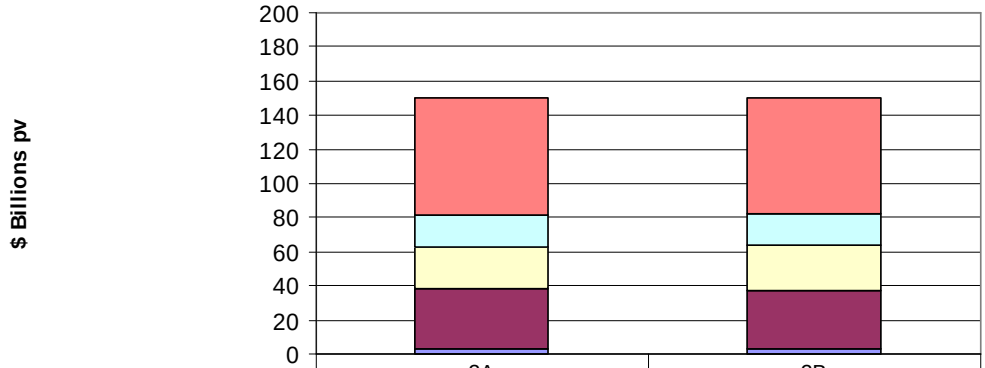
Source: SENES, OPA

2.9.4.2 Costs, Risks and Sensitivities

Figure 2.9.13 below shows the present value of cash flows. The costs of the two portfolios are very similar.

Figure 2.9.14 outlines capital expenditures for Portfolio 2A and 2B. Total capital expenditures are $41.61 billion and $38.1 billion, respectively (present value). Table 2.9.5 details the capital expenditures as spent. The expenditures between the two Portfolios differ only during the period of 2012 to 2020. Figure 2.9.15 illustrates capital expenditures as spent for Portfolio 2A.

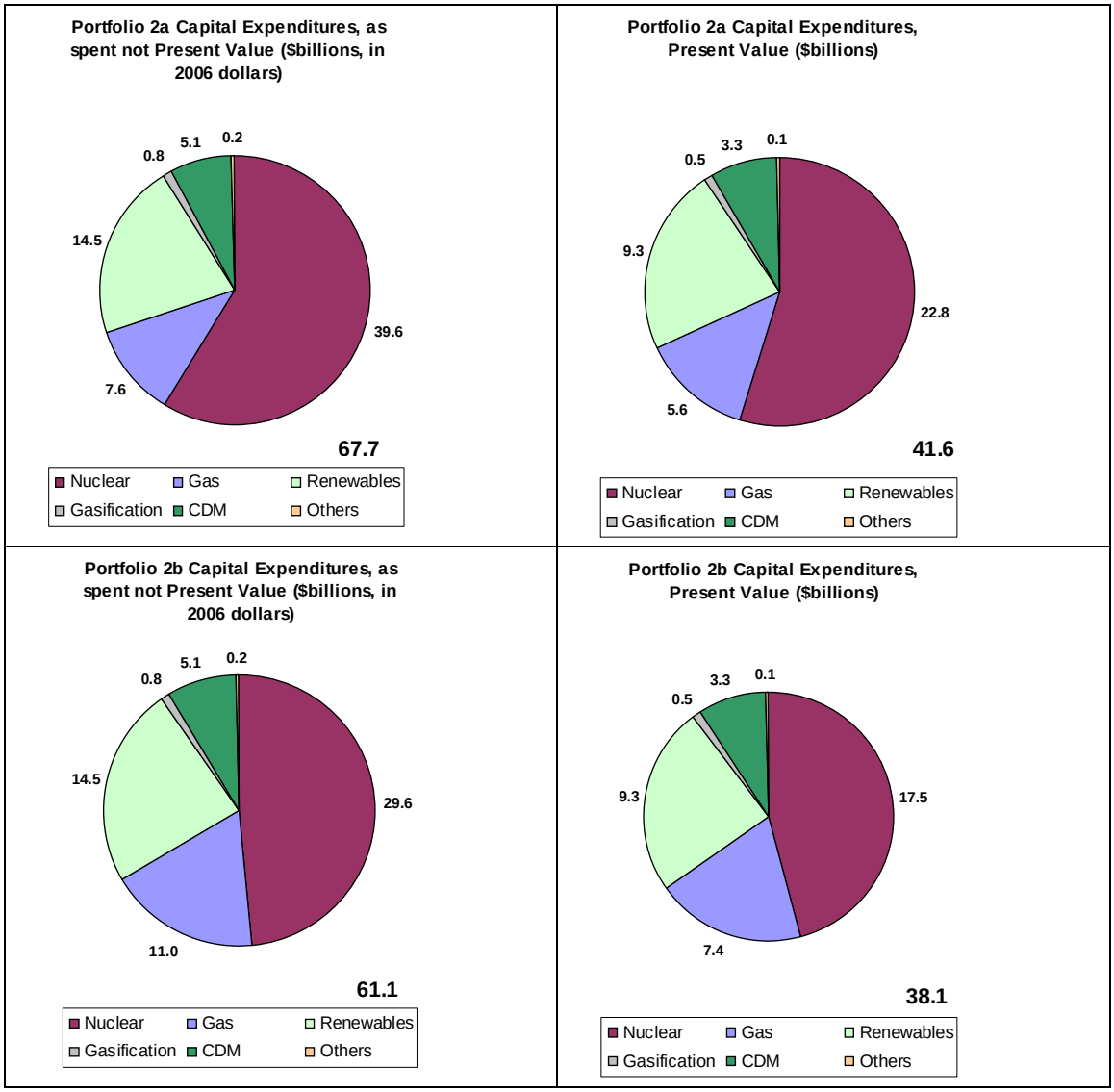
Figure 2.9.13 – Portfolios 2A and 2B - Present Value of Cash Flow Components



	2A	2B
Total	150	150
Long Term (Post 2025)	69	68
Capital Charged to Study Period	19	18
Fuel & Variable OM&A	24	27
Fixed OM&A	35	34
CDM	3	3

Source: OPA

Figure 2.9.14 – Portfolios 2A and 2B: Capital Expenditures



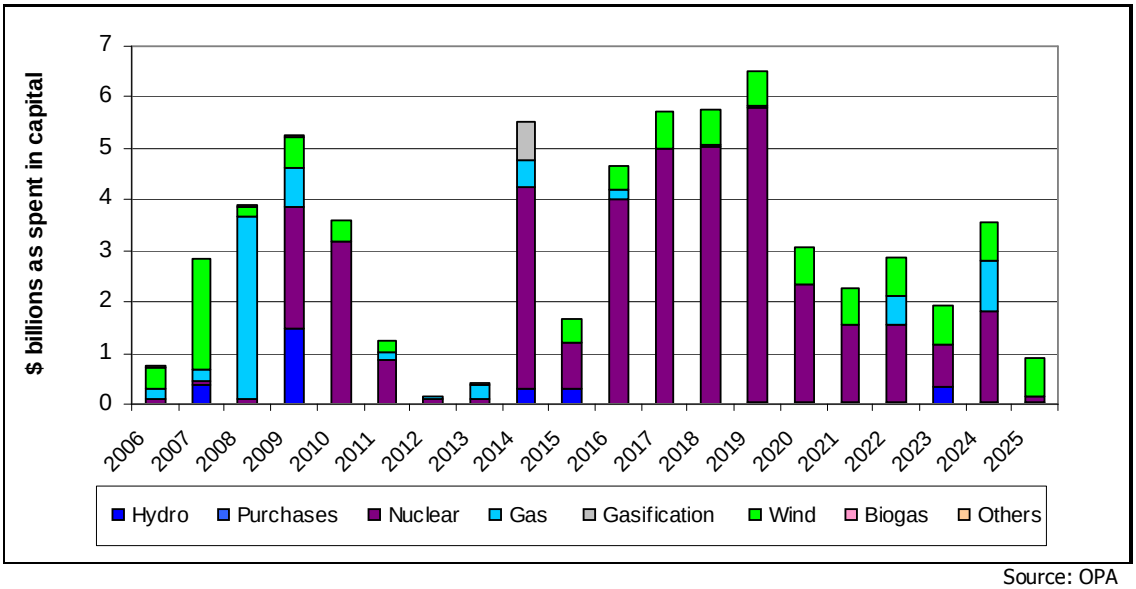
Source: OPA

Table 2.9.5 – Portfolios 2A and 2B – Annual Capital Expenditures, As Spent, not Present Value ($ Billions, 2006 Dollars)

Capital Expenditures 2a																					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	4.98	5.03	5.78	2.33	1.52	1.52	0.82	1.80	0.12	39.59
Gas	0.18	0.23	3.54	0.76	0.02	0.16	0.02	0.27	0.52	0.02	0.20	0.02	0.02	0.02	0.02	0.02	0.59	0.02	0.99	0.02	7.61
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.02	0.32	0.77	0.47	0.71	0.71	0.72	0.73	0.73	0.74	1.08	0.76	0.76	14.49
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77
CDM	0.03	0.07	0.14	0.23	0.34	0.46	0.56	0.61	0.58	0.53	0.40	0.25	0.29	0.15	0.12	0.11	0.09	0.06	0.03	0.01	5.07
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.77**	**2.92**	**4.04**	**5.49**	**3.95**	**1.70**	**0.71**	**1.01**	**6.10**	**2.20**	**5.07**	**5.95**	**6.05**	**6.67**	**3.20**	**2.39**	**2.95**	**1.98**	**3.58**	**0.93**	**67.69**
Capital Expenditures 2b																					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	1.70	2.41	2.33	1.52	1.52	0.82	1.80	0.12	29.60
Gas	0.18	0.23	3.54	0.76	0.02	0.16	0.02	0.02	1.07	0.51	0.02	0.77	1.56	0.02	0.54	0.02	0.59	0.02	0.99	0.02	11.02
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.02	0.02	0.77	0.47	0.71	0.71	1.03	0.73	0.73	0.74	1.08	0.76	0.76	14.50
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77
CDM	0.03	0.07	0.14	0.23	0.34	0.46	0.56	0.61	0.58	0.53	0.40	0.25	0.29	0.15	0.12	0.11	0.09	0.06	0.03	0.01	5.07
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.77**	**2.92**	**4.04**	**5.49**	**3.95**	**1.70**	**0.71**	**0.76**	**6.35**	**2.70**	**4.89**	**3.40**	**4.26**	**3.63**	**3.72**	**2.39**	**2.95**	**1.98**	**3.58**	**0.93**	**61.14**

Source: OPA

Figure 2.9.15 – Portfolio 2A – Capital Expenditures



Source: OPA

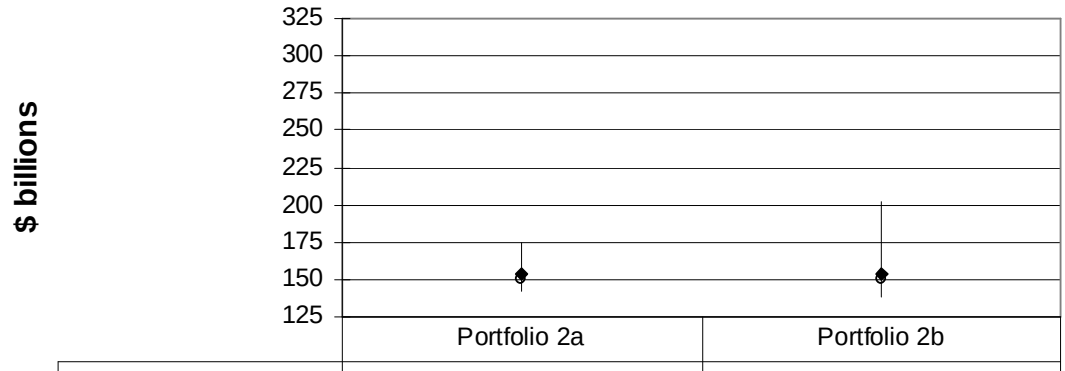
Figure 2.9.16 shows the stochastic and deterministic average of the present value of cash flows for Portfolios 2A and 2B together with the range of variability of the results. The difference in cost of the two portfolios is small compared to the range of uncertainty in the expected costs. In addition, Portfolio 2B has a larger range of uncertainty.

Figure 2.9.17 illustrates the breakdown of the contributions to the uncertainty around costs. In both Portfolios, natural gas price volatility is the largest contributor to cost risk. As Portfolio 2B relies more heavily on natural gas-fired generation, it exhibits greater variability around natural gas fuel price.

Whereas Figure 2.9.17 illustrates the standard deviation of results, Figure 2.9.18 illustrates the stochastic minimum and maximum values. Figure 2.9.18 shows that the risk spread of Portfolio 2B is greater than that of Portfolio 2A, and is principally driven by natural gas price risk.

Figure 2.9.19 summarizes the results of the sensitivity studies applied to the Portfolios The sensitivities show that portfolio 2A is less expensive than portfolio 2B under the assumed possible futures except when considering a low gas price scenario.

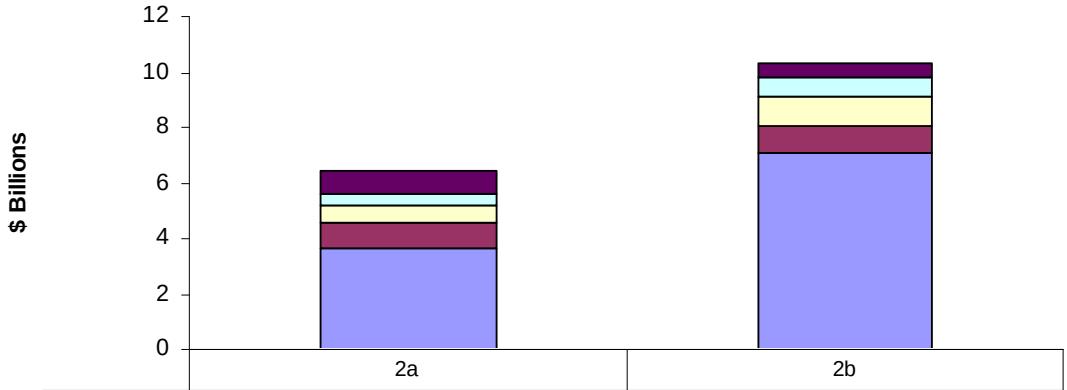
Figure 2.9.16 – Portfolios 2A and 2B – Present Value of Cash Flows



	Portfolio 2a	Portfolio 2b
Maximum	174.08	202.00
Minimum	142.63	138.52
◆ Stochastic Average	153.24	153.31
○ Deterministic Average	150.34	150.25

Source: OPA

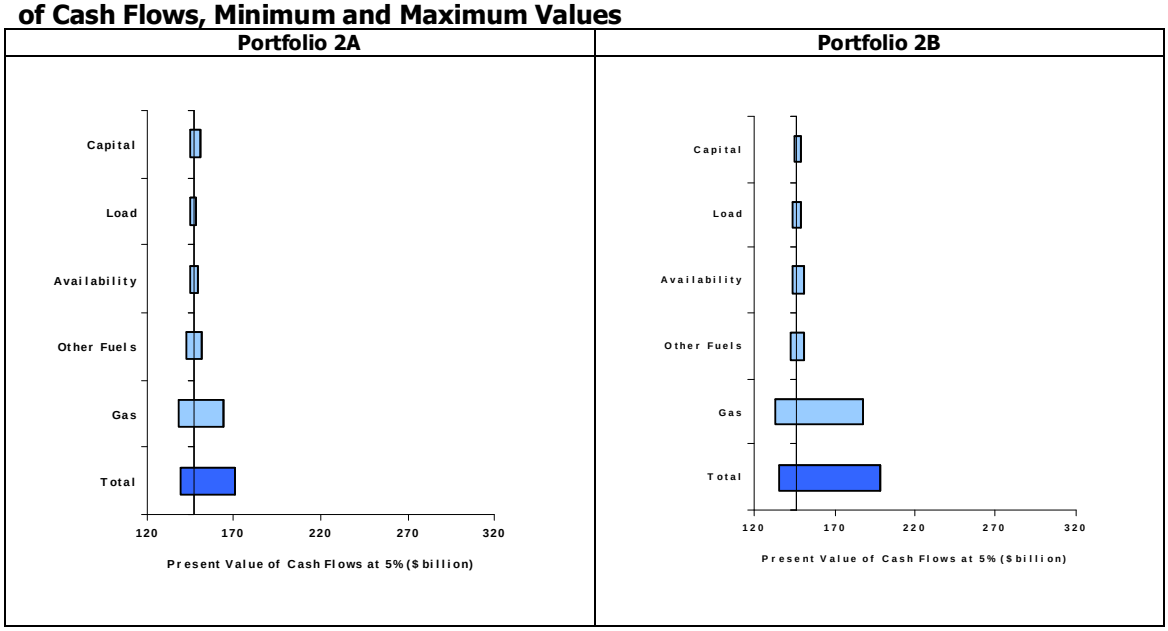
Figure 2.9.17 – Portfolios 2A and 2B – Indicative Volatility Contribution, Present Value of Cash Flows, Standard Deviation



	2a	2b
Capital	0.83	0.48
Load	0.44	0.76
Availability	0.61	1.01
Other Fuel	0.91	0.96
Natural Gas	3.65	7.12

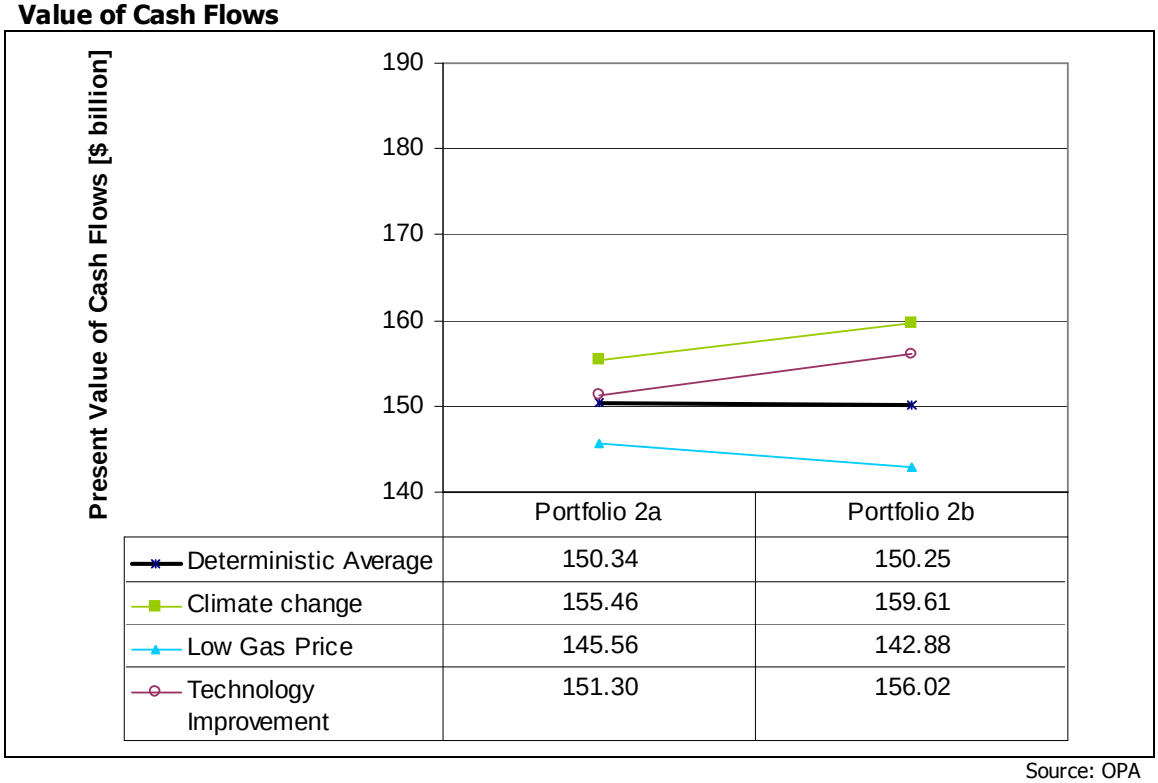
Source: OPA

Figure 2.9.18 – Portfolios 2A and 2B – Indicative Volatility Contribution, Present Value of Cash Flows, Minimum and Maximum Values



Source: OPA

Figure 2.9.19 – Portfolios 2A and 2B - Deterministic Sensitivity Analysis, Present Value of Cash Flows



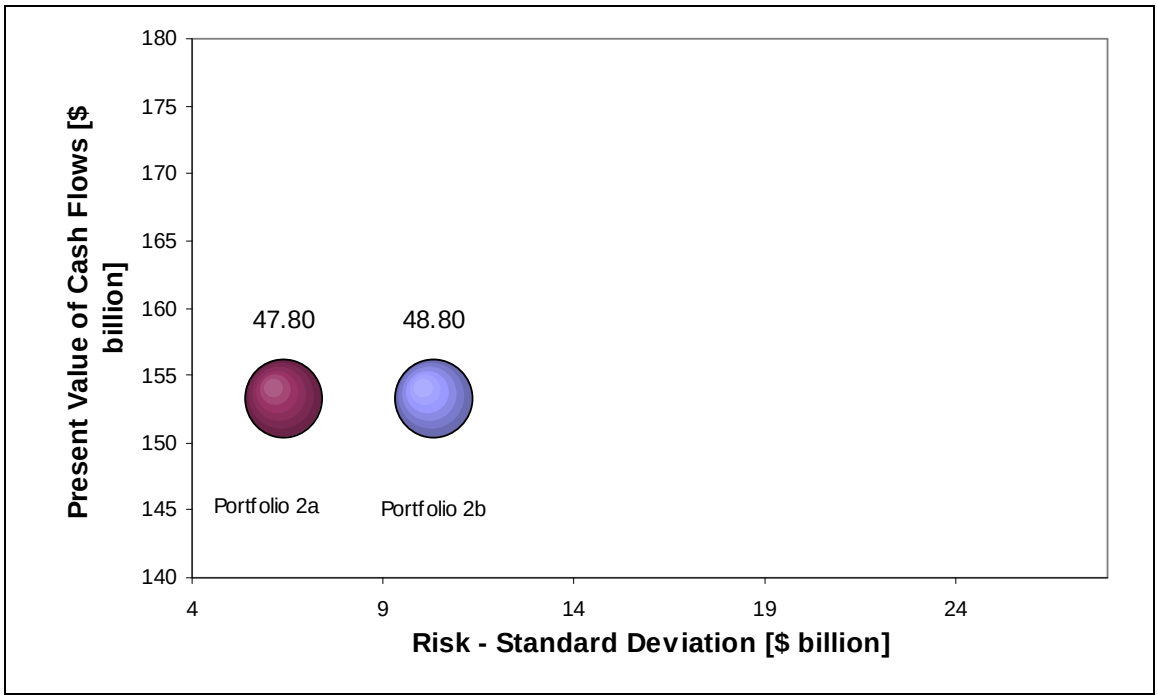
	Portfolio 2a	Portfolio 2b
Deterministic Average	150.34	150.25
Climate change	155.46	159.61
Low Gas Price	145.56	142.88
Technology Improvement	151.30	156.02

Source: OPA

2.9.4.3 Combined Cost, Risk, and Environmental Loading

Figure 2.9.20 summarizes the cost, risk and environmental loading score of Portfolios 2A and 2B. It indicates that Portfolio 2B, which relies more heavily on natural gas-fired generation, is slightly less expensive than Portfolio 2A, but entails greater risk and results in a higher environmental impact.

Figure 2.9.20 – Portfolios 2A and 2B - Cost/Risk/Environmental Loading Score



Source: OPA

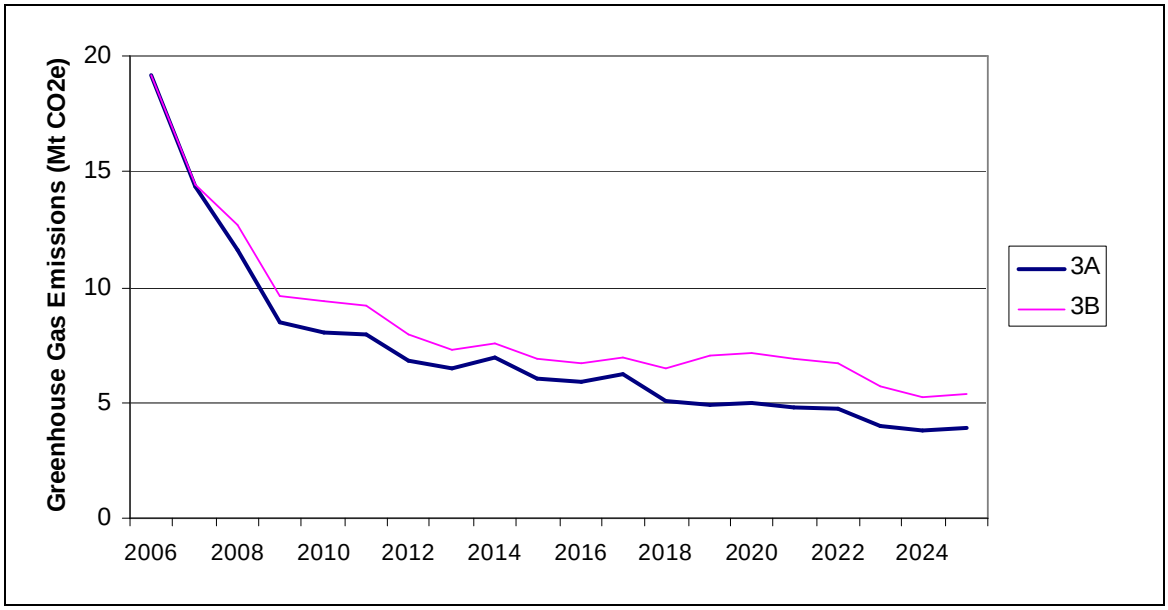
2.9.5 Scenario 3 (Delayed Coal Replacement)

2.9.5.1 Environmental Impacts

The annual greenhouse gas emissions for Portfolios 3A and 3B are shown in Figure 2.9.21. It can be seen that Portfolio 3B, with its higher use of natural gas-fired generation, results in higher greenhouse gas emissions. Total greenhouse gas emissions over the study period are 217 Mt CO_2e for Portfolio 3A, and 251 MT CO_2e for Portfolio 3B.

The environmental loading scores of the Portfolios during the study period and beyond, including the breakdown of the different contributions to the score, are shown in Figure 2.9.22. Portfolio 3A results in a lower environmental loading score than Portfolio 3B, and this can be expected to be sustained in the longer-term. The absolute values associated with each portfolio are presented in Table 2.9.6.

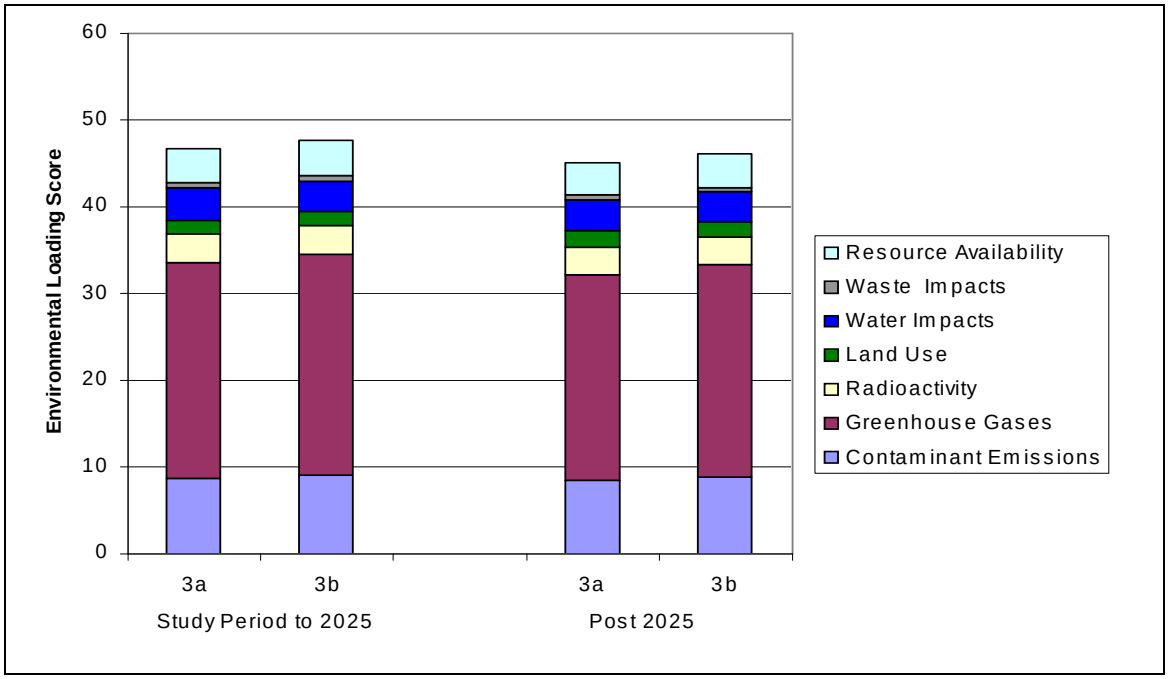
Figure 2.9.21 – Portfolios 3A and 3B - Annual Greenhouse Gas Emissions



Note: Greenhouse gases analyzed include carbon dioxide, methane and nitrous oxide

Source: OPA

Figure 2.9.22 – Portfolios 3A and 3B - Environmental Loading Scores by Impact



Source: OPA

Table 2.9.6 – Portfolios 3A and 3B - Absolute Environmental Loading Values

Indicator	Metric	Portfolio 3A	Portfolio 3B
Contaminant Emissions	kT	1007	1063
Greenhouse Gas Emissions	Mt CO2e	217	251
Radioactivity	Sv	3178	3022
Land Use	km2	1119.3	1116.2
Water Use – Withdrawal	TL	496	478
Water Use - Consumption	TL	2.81	2.82
Waste	kT	310	321

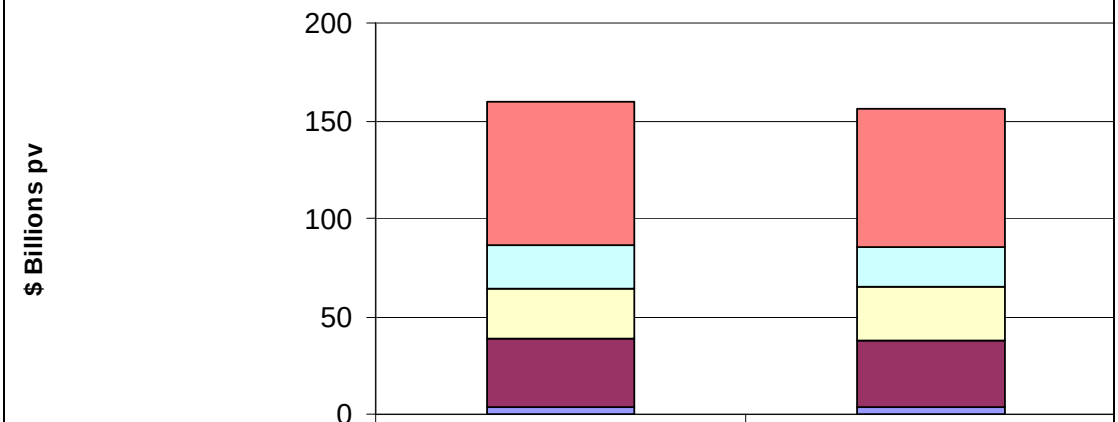
Source: SENES, OPA

2.9.5.2 Costs, Risks and Sensitivities

Figure 2.9.23 shows the present value of cash flows. The costs of the two portfolios are very similar, with Portfolio 3B showing a slight cost advantage.

Figure 2.9.24 outlines capital expenditures for Portfolios 3A and 3B. Total capital expenditures are $45.6 billion and $42.7 billion, respectively (present value). Table 2.9.7 outlines capital expenditures as spent. Figure 2.9.25 illustrates capital expenditures, as spent for Portfolio 3A.

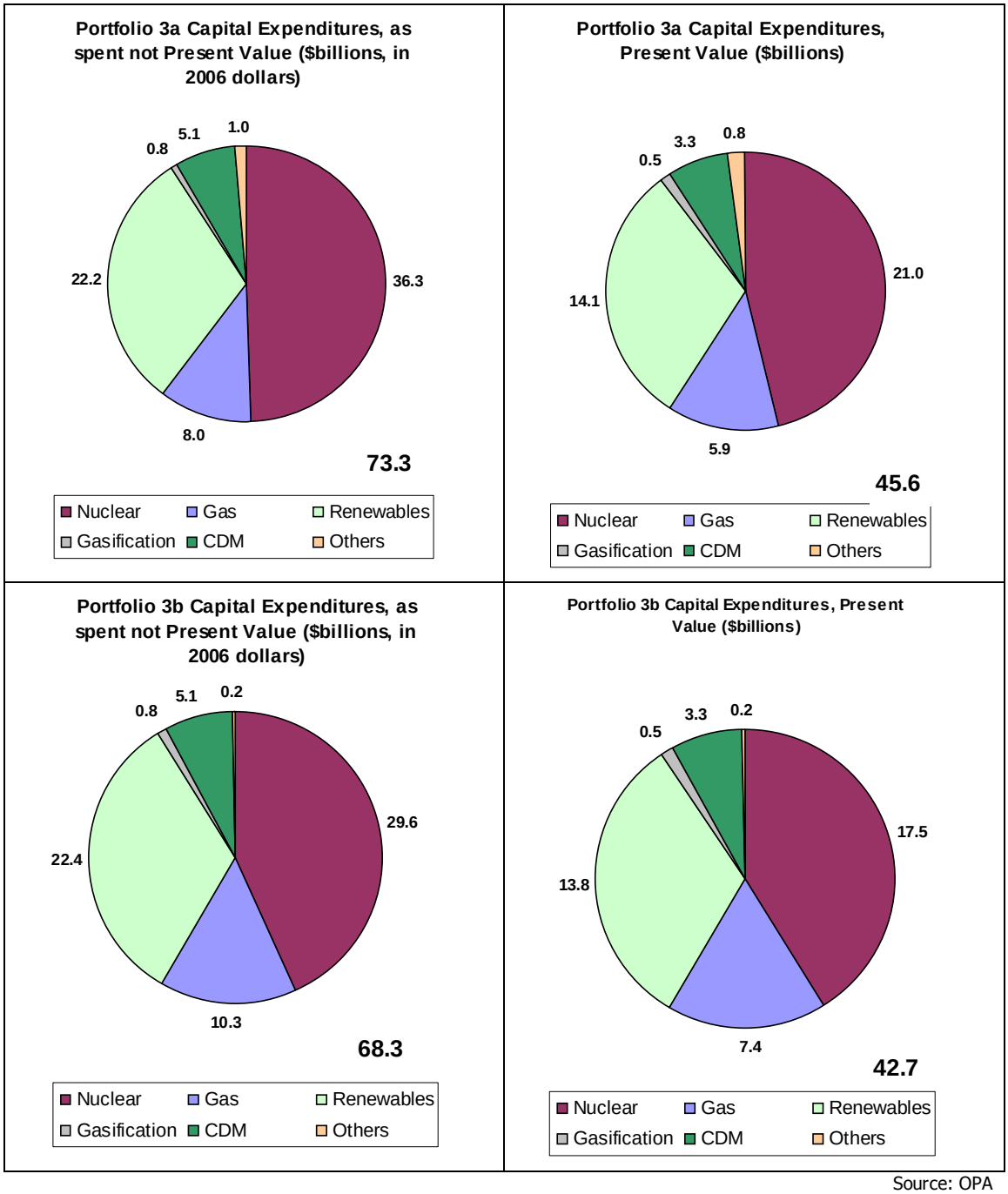
Figure 2.9.23 – Portfolios 3A and 3B - Present Value of Cash Flow Components



	3A	3B
Total	159	156
Long Term (Post 2025)	73	71
Capital Charged to Study Period	21	20
Fuel & Variable OM&A	26	27
Fixed OM&A	35	35
CDM	3	3

Source: OPA

Figure 2.9.24 – Portfolios 3A and 3B – Capital Expenditures



Source: OPA

Table 2.9.7 – Portfolios 3A and 3B – Annual Capital Expenditures, As Spent, not Present Value ($ Billions, 2006 Dollars)

Capital Expenditures 3a

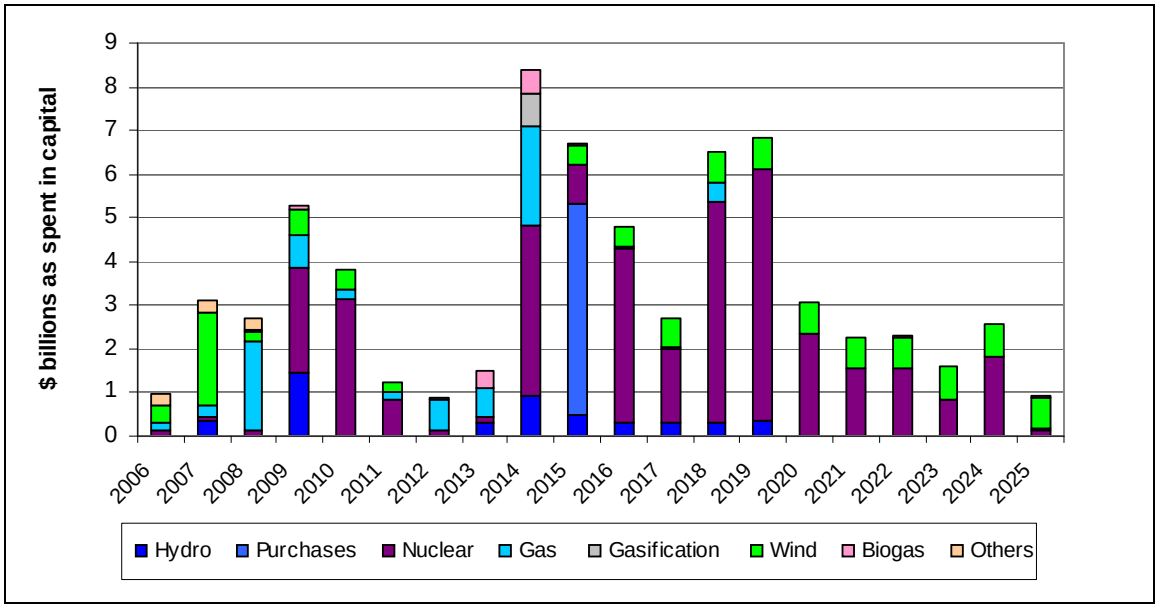
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	5.03	5.78	2.33	1.52	1.52	0.82	1.80	0.12	36.29
Gas	0.18	0.23	2.07	0.76	0.22	0.16	0.73	0.70	2.27	0.02	0.02	0.02	0.46	0.02	0.02	0.02	0.02	0.02	0.02	0.02	7.95
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.70	1.44	5.77	0.78	1.01	1.02	1.03	0.73	0.73	0.74	0.75	0.76	0.76	22.22
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77
CDM	0.03	0.07	0.14	0.23	0.34	0.46	0.56	0.61	0.58	0.53	0.40	0.25	0.29	0.15	0.12	0.11	0.09	0.06	0.03	0.01	5.07
Others	0.27	0.27	0.27	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.97
Total	**1.02**	**3.17**	**2.82**	**5.51**	**4.17**	**1.72**	**1.44**	**2.13**	**8.98**	**7.21**	**5.19**	**2.96**	**6.80**	**6.99**	**3.20**	**2.39**	**2.38**	**1.66**	**2.62**	**0.93**	**73.27**

Capital Expenditures 3b

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	Total
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	1.70	2.41	2.33	1.52	1.52	0.82	1.80	0.12	29.60
Gas	0.18	0.23	3.54	0.76	1.64	0.16	0.26	0.23	0.39	0.02	0.02	0.64	0.21	0.21	0.21	0.02	0.59	0.02	0.99	0.02	10.31
Renewables	0.44	2.49	0.24	1.25	0.73	0.23	0.02	0.70	0.32	6.15	0.93	1.01	1.02	1.03	1.04	0.73	1.07	1.08	1.09	0.76	22.36
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.77
CDM	0.03	0.07	0.14	0.23	0.34	0.46	0.56	0.61	0.58	0.53	0.40	0.25	0.29	0.15	0.12	0.11	0.09	0.06	0.03	0.01	5.07
Others	0.03	0.03	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.23
Total	**0.77**	**2.92**	**4.04**	**4.65**	**5.88**	**1.72**	**0.97**	**1.66**	**5.97**	**7.59**	**5.35**	**3.59**	**3.22**	**3.82**	**3.71**	**2.39**	**3.27**	**1.98**	**3.91**	**0.93**	**68.34**

Source: OPA

Figure 2.9.25 – Portfolio 3A – Capital Expenditures



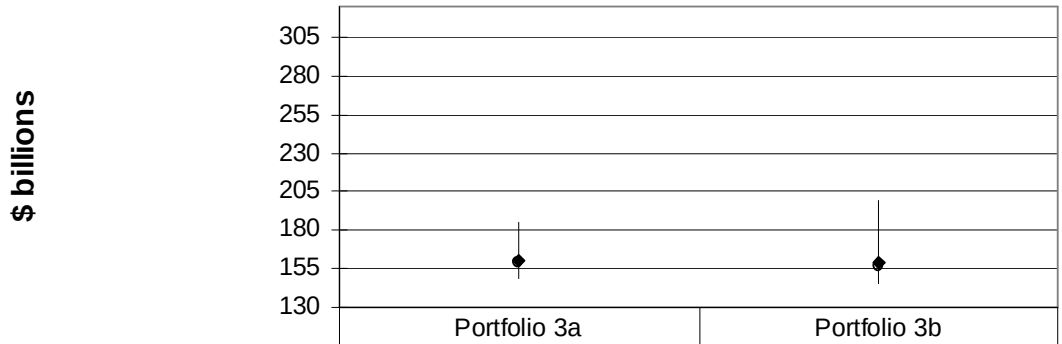
Source: OPA

Figure 2.9.26 shows the stochastic and deterministic average of the present value of cash flows for Portfolios 3A and 3B, together with the range in variation of the results. The difference in cost between the two portfolios is small compared to the range of uncertainty in the expected costs. Portfolio 3B, however, has a larger range of uncertainty.

Figure 2.9.27 illustrates the breakdown of the contributions to the variation around costs. In both Portfolios, natural gas price volatility is the largest contributor to cost risk. As Portfolio 3B relies more heavily on natural gas-fired generation, it exhibits greater variability around natural gas fuel price.

Whereas Figure 2.9.27 illustrates the standard deviation of results, Figure 2.9.28 illustrates the stochastic minimum and maximum values. Figure 2.9.28 shows that the risk spread of Portfolio 3B is greater than that of Portfolio 3A, and is principally driven by natural gas price volatility.

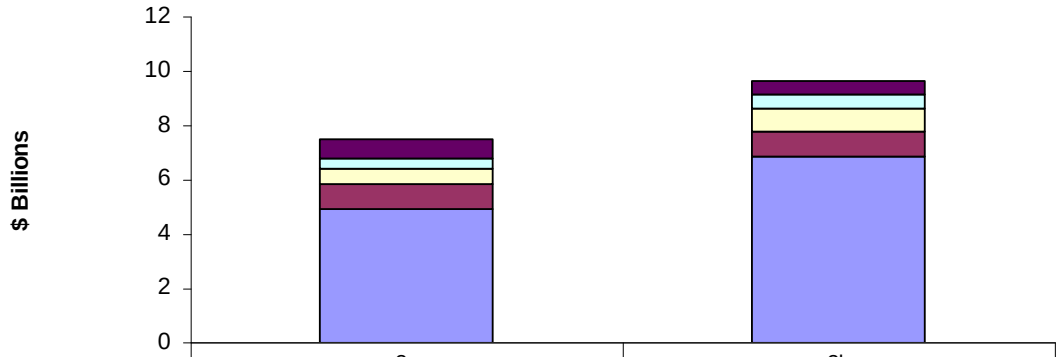
Figure 2.9.26 – Portfolios 3A and 3B - Present Value of Cash Flows



	Portfolio 3a	Portfolio 3b
Maximum	185.32	198.66
Minimum	149.47	145.29
◆ Stochastic Average	160.78	159.26
○ Deterministic Average	159.21	156.34

Source: OPA

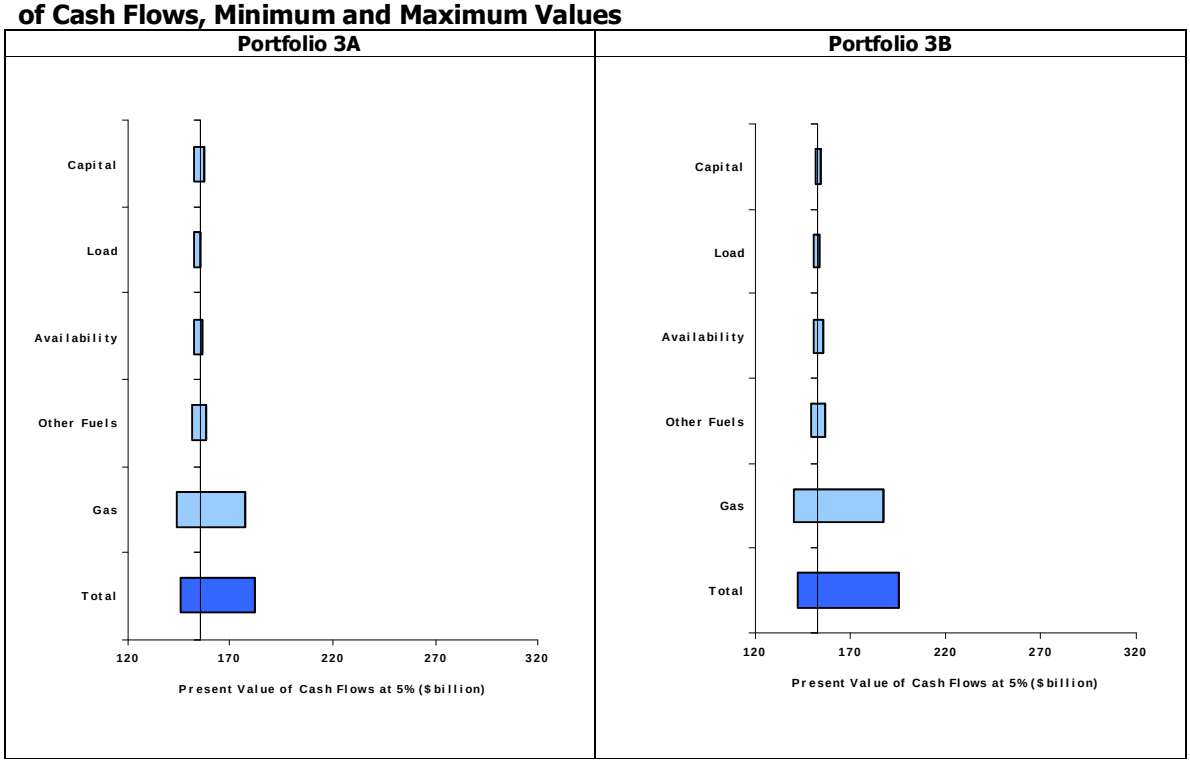
Figure 2.9.27 – Portfolios 3A and 3B - Indicative Volatility Contribution, Present Value of Cash Flows, Standard Deviation



	3a	3b
Capital	0.75	0.49
Load	0.37	0.52
Availability	0.59	0.85
Other Fuel	0.88	0.92
Natural Gas	4.94	6.86

Source: OPA

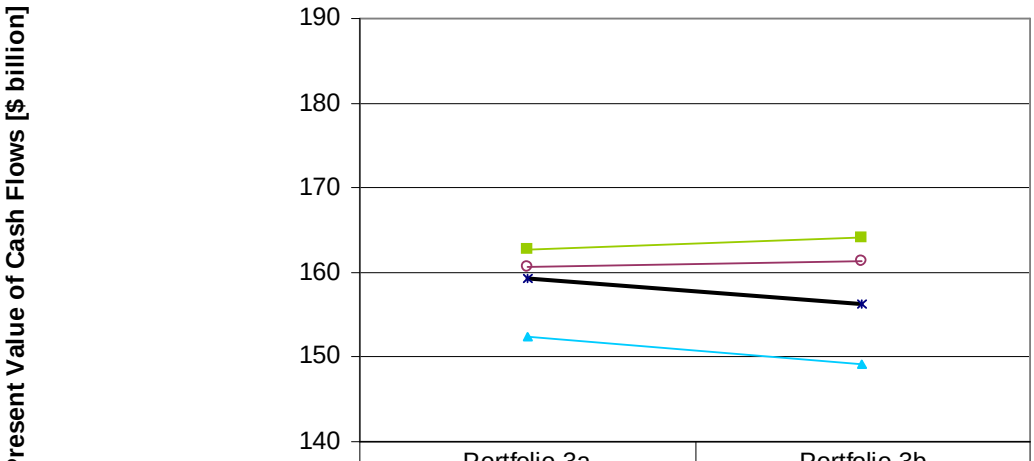
Figure 2.9.28 – Portfolios 3A and 3B – Indicative Volatility Contribution, Present Value of Cash Flows, Minimum and Maximum Values



Source: OPA

Figure 2.9.29 summarizes the results of the sensitivity studies applied to the Portfolios. Portfolio 3A shows a lower cost under the climate change and technology improvement sensitivities, while Portfolio 3B shows lower cost under the low natural gas price sensitivity.

Figure 2.9.29 – Portfolios 3A and 3B - Deterministic Sensitivity Analysis, Present Value of Cash Flows



	Portfolio 3a	Portfolio 3b
Deterministic Average	159.21	156.34
Climate change	162.76	164.04
Low Gas Price	152.43	149.19
Technology Improvement	160.62	161.36

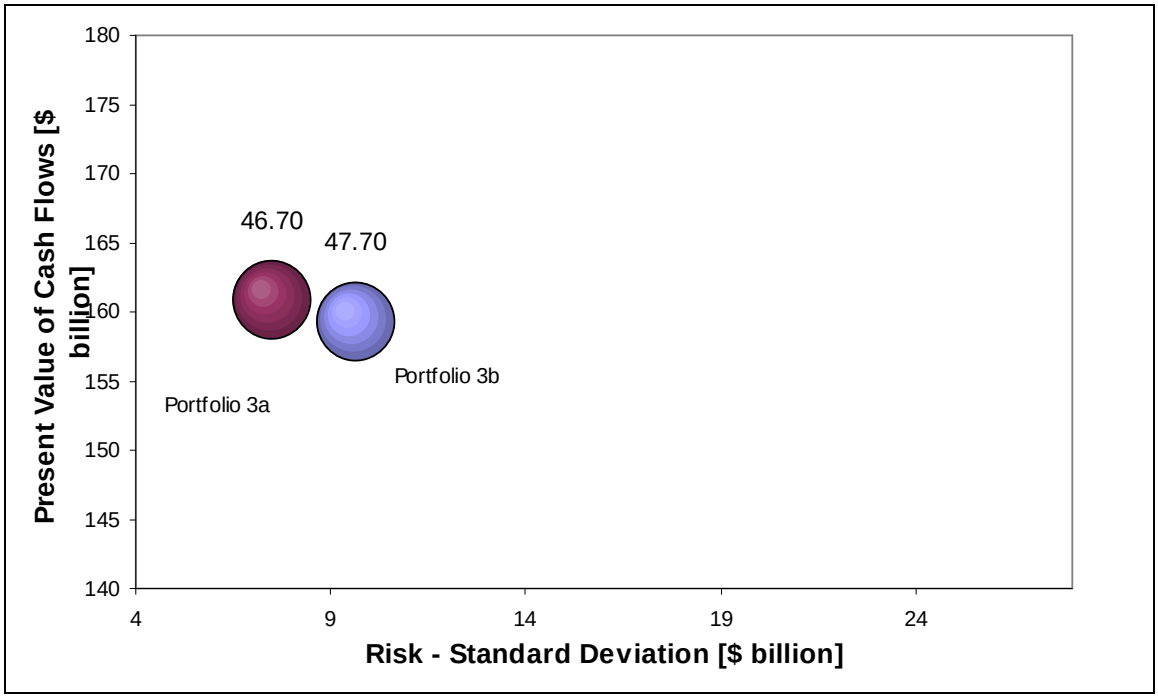
Source: OPA

2.9.5.3 Combined Cost, Risk, and Environmental Loading

Figure 2.9.30 summarizes the cost, risk and environmental loading score of Portfolios 3A and 3B.

Figure 2.9.30 indicates that Portfolio 3B, which relies more heavily on natural gas-fired generation, is slightly less expensive than Portfolio 3A, but entails greater risk and results in a higher environmental impact. The slightly higher cost of Portfolio 3A reflects the expenditure on additional environmental control technology in the short term, and greater investment in nuclear plant in the mid-to-longer term.

Figure 2.9.30 – Portfolios 3A and 3B – Cost/Risk/Environmental Loading Score



Source: OPA

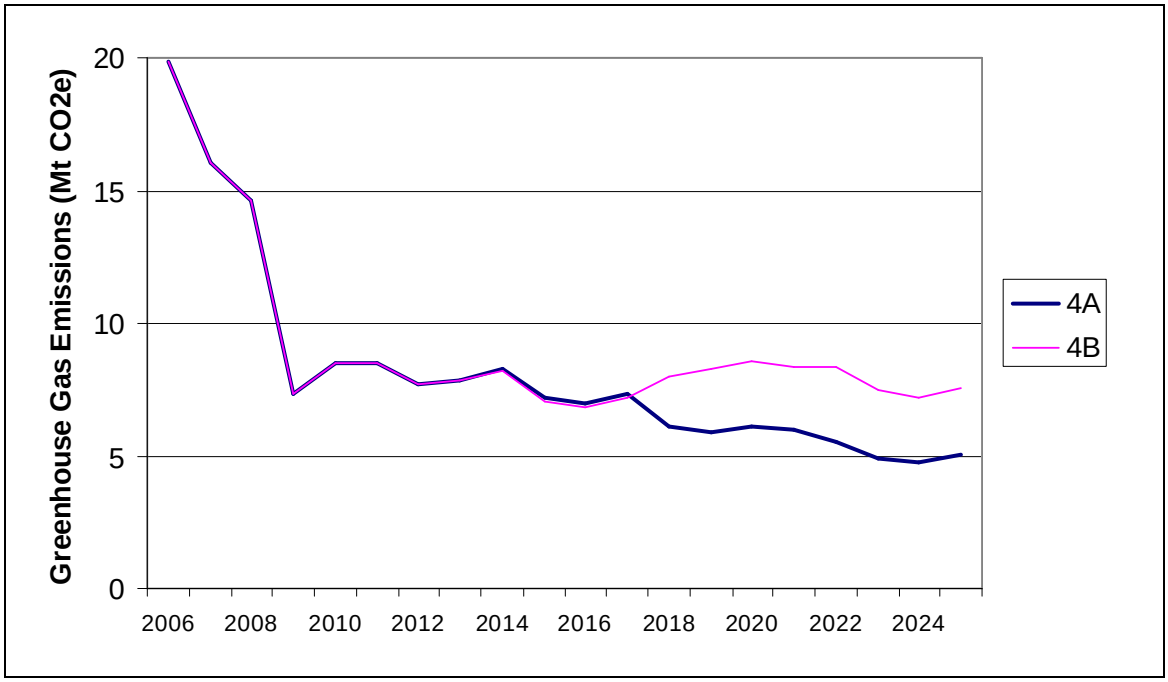
2.9.6 Scenario 4 (High Demand)

2.9.6.1 Environmental Impacts

The annual greenhouse gas emissions for Portfolios 4A and 4B are shown in Figure 2.9.31. Portfolio 4B, with its higher use of natural gas-fired generation, results in higher greenhouse gas emissions. Total greenhouse gas emissions over the study period are 243 Mt CO_2e for Portfolio 4A, and 266 MT CO_2e for Portfolio 4B.

The environmental loading scores of the Portfolios during the study period and beyond, including the breakdown of the different contributions to the score, are shown in Figure 2.9.32. Portfolio 4A results in a lower environmental loading score than Portfolio 4B, and this can be expected to be sustained in the longer-term. The absolute values associated with each portfolio are presented in Table 2.9.8.

Figure 2.9.31 – Portfolios 4A and 4B - Annual Greenhouse Gas Emissions



Note: Greenhouse gases analyzed include carbon dioxide, methane and nitrous oxide.

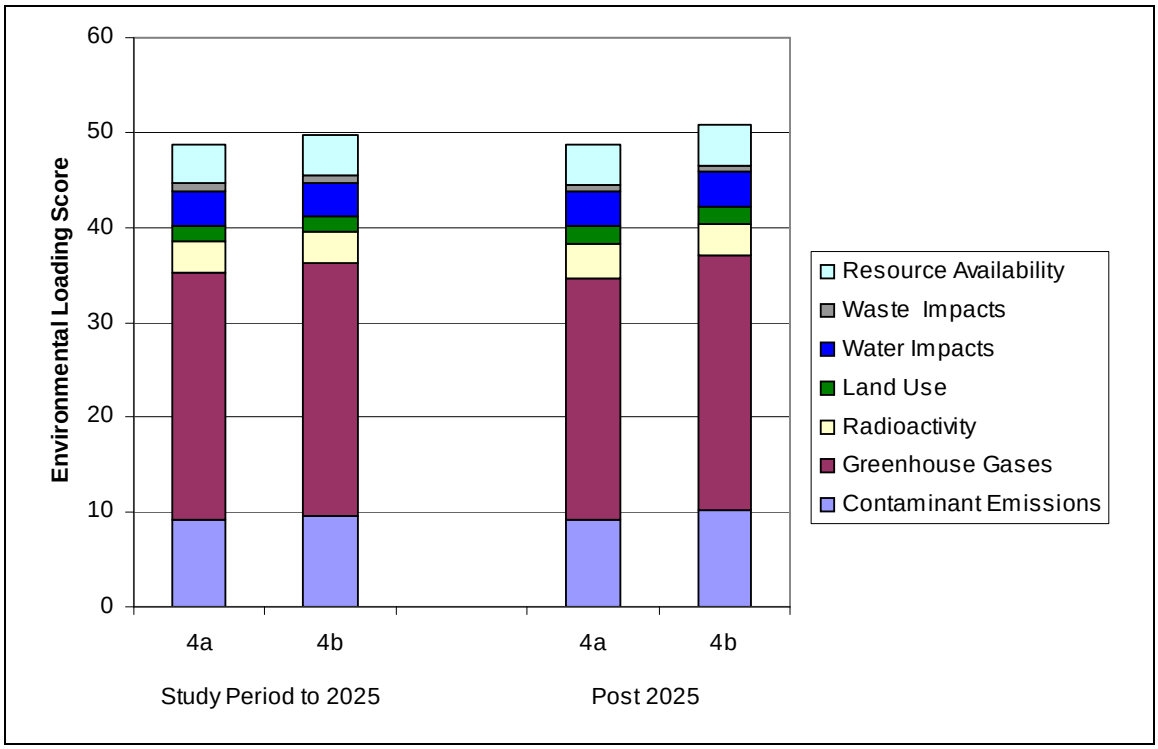
Source: OPA

Table 2.9.8 – Portfolios 4A and 4B - Absolute Environmental Loading Values

Indicator	Metric	Portfolio 4A	Portfolio 4B
Contaminant Emissions	kT	1064	1120
Greenhouse Gas Emissions	Mt CO2e	243	266
Radioactivity	Sv	2920	2846
Land Use	km2	1119.2	1120.7
Water Use – Withdrawal	TL	503	483
Water Use - Consumption	TL	2.95	2.88
Waste	kT	283	277

Source: SENES, OPA

Figure 2.9.32 – Portfolios 4A and 4B – Environmental Loading Scores by Impact



Source: OPA

2.9.6.2 Costs, Risks and Sensitivities

Figure 2.9.33 below shows the present value of cash flows. The total costs of the two portfolios are very similar.

Figure 2.9.34 outlines capital expenditures for Portfolios 4A and 4B. Total capital expenditures for the Portfolios are $51.5 billion and $49.4 billion, respectively (present value). Table 2.9.9 details capital expenditures as spent. Differences relate largely to expenditures during the mid-to-late period of the study term.

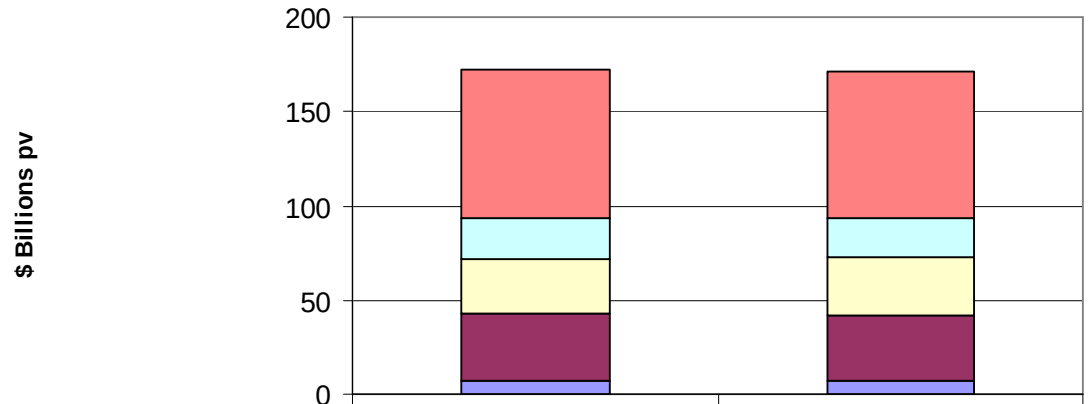
Figure 2.9.35 below shows the stochastic and deterministic average of the present value of cash flows for Portfolios 4A and 4B, together with the range in variability of the results. The range of variability around the expected costs represents the largest cost-related distinction between the two Portfolios. In addition, Portfolio 4B has a notably larger range of variability.

Figure 2.9.36 illustrates the breakdown of the contributions to the variability around costs. In both Portfolios, natural gas price volatility is the largest contributor to cost risk.

As Portfolio 4B relies more heavily on natural gas-fired generation, it exhibits greater variability around natural gas fuel price.

Whereas Figure 2.9.36 illustrates the standard deviation of results, Figure 2.9.37 illustrates the stochastic minimum and maximum values. Figure 2.9.37 shows that the risk spread of Portfolio 4B is greater than that of Portfolio 4A, and is principally driven by natural gas price risk.

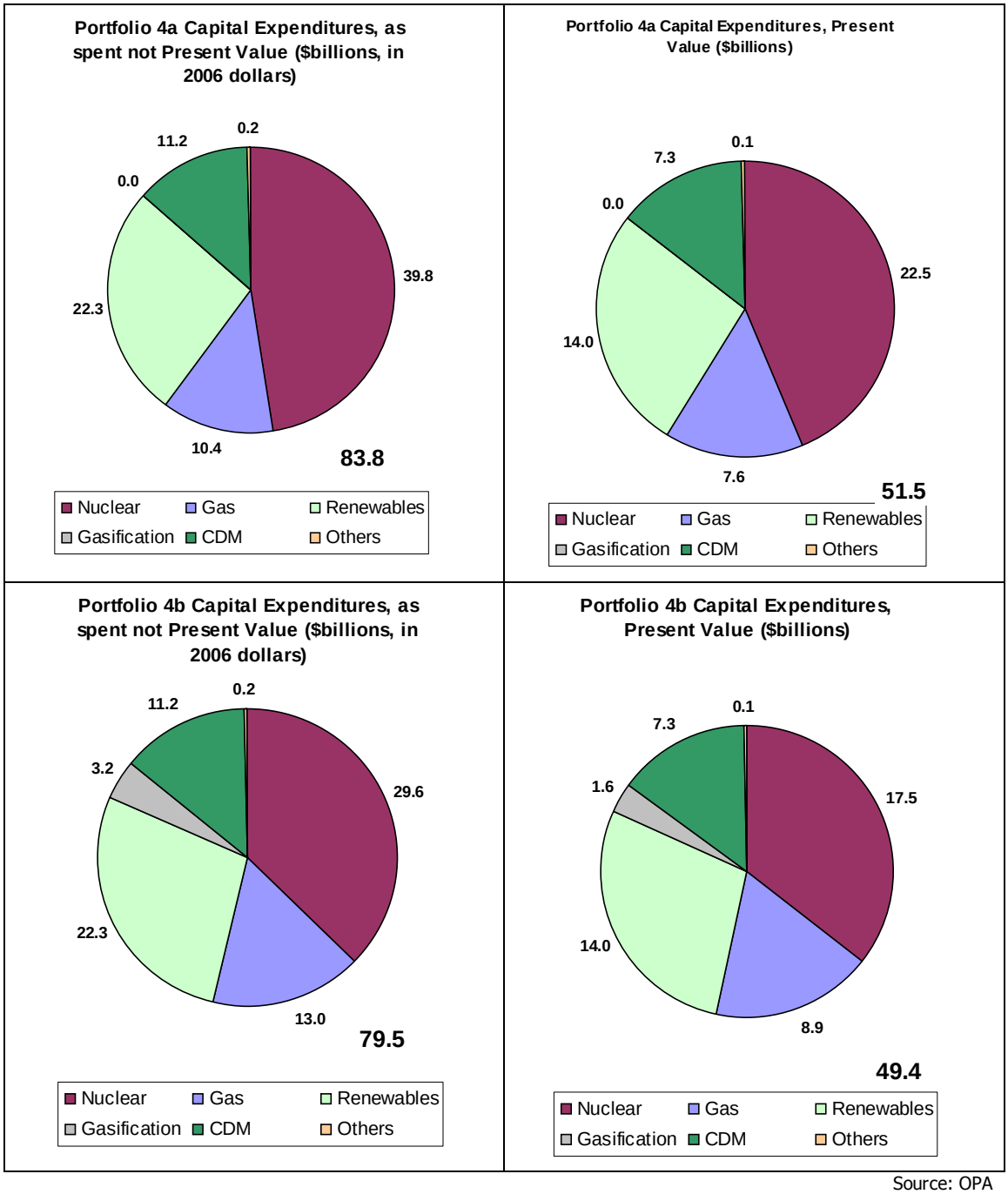
Figure 2.9.33 – Portfolios 4A and 4B - Present Value of Cash Flow Components



	4A	4B
Total	172	172
Long Term (Post 2025)	78	78
Capital Charged to Study Period	22	21
Fuel & Variable OM&A	29	30
Fixed OM&A	35	35
CDM	7	7

Source: OPA

Figure 2.9.34 – Portfolios 4A and 4B – Capital Expenditures



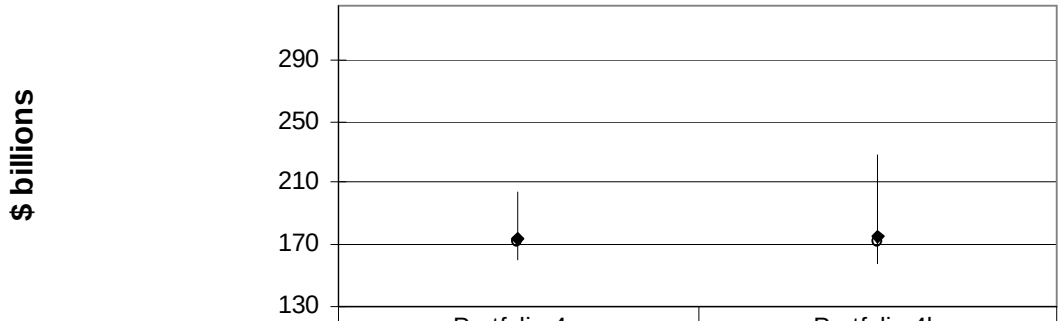
Source: OPA

Table 2.9.9 – Portfolios 4A and 4B – Annual Capital Expenditures, As Spent, not Present Value ($ Billions, 2006 Dollars)

Capital Expenditures 4a																					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	5.03	5.78	2.33	1.52	4.99	0.82	1.80	0.12	39.76
Gas	0.18	0.23	3.54	0.76	1.64	0.16	0.40	0.23	0.75	0.02	0.02	0.45	0.93	0.57	0.02	0.02	0.02	0.02	0.02	0.42	10.39
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.41	0.84	5.62	0.93	0.71	1.34	1.66	0.73	0.73	1.07	0.75	0.76	0.76	22.28
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CDM	0.06	0.16	0.31	0.51	0.75	1.02	1.24	1.34	1.27	1.17	0.89	0.54	0.63	0.34	0.27	0.23	0.19	0.13	0.08	0.03	11.16
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.81**	**3.01**	**4.21**	**5.77**	**5.99**	**2.26**	**1.77**	**2.09**	**6.79**	**7.69**	**5.83**	**3.39**	**7.93**	**8.36**	**3.35**	**2.51**	**6.27**	**1.73**	**2.66**	**1.35**	**83.76**
Capital Expenditures 4b																					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	1.70	2.41	2.33	1.52	1.52	0.82	1.80	0.12	29.60
Gas	0.18	0.23	3.54	1.00	1.64	0.16	0.26	0.23	0.57	0.02	0.02	0.45	1.67	0.13	0.67	0.02	1.13	0.02	0.99	0.10	13.01
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.41	1.14	5.62	0.93	0.71	1.02	1.35	0.73	0.73	0.74	1.08	1.09	0.76	22.29
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.78	0.00	0.00	0.00	0.81	0.00	0.82	0.00	0.84	0.00	0.00	3.24
CDM	0.06	0.16	0.31	0.51	0.75	1.02	1.24	1.34	1.27	1.17	0.89	0.54	0.63	0.34	0.27	0.23	0.19	0.13	0.08	0.03	11.16
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.81**	**3.01**	**4.21**	**6.01**	**5.99**	**2.26**	**1.63**	**2.09**	**6.90**	**8.47**	**5.83**	**3.39**	**5.03**	**5.04**	**4.01**	**3.34**	**3.59**	**2.90**	**3.96**	**1.02**	**79.48**

Source: OPA

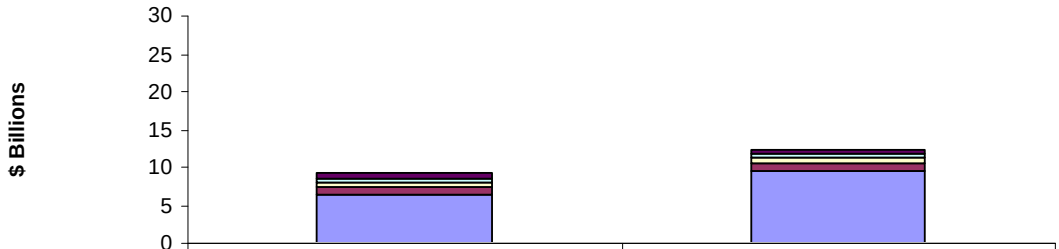
Figure 2.9.35 – Portfolios 4A and 4B - Present Value of Cash Flows



	Portfolio 4a	Portfolio 4b
Maximum	204.72	227.90
Minimum	160.53	157.62
◆ Stochastic Average	174.24	174.96
○ Deterministic Average	171.89	171.52

Source: OPA

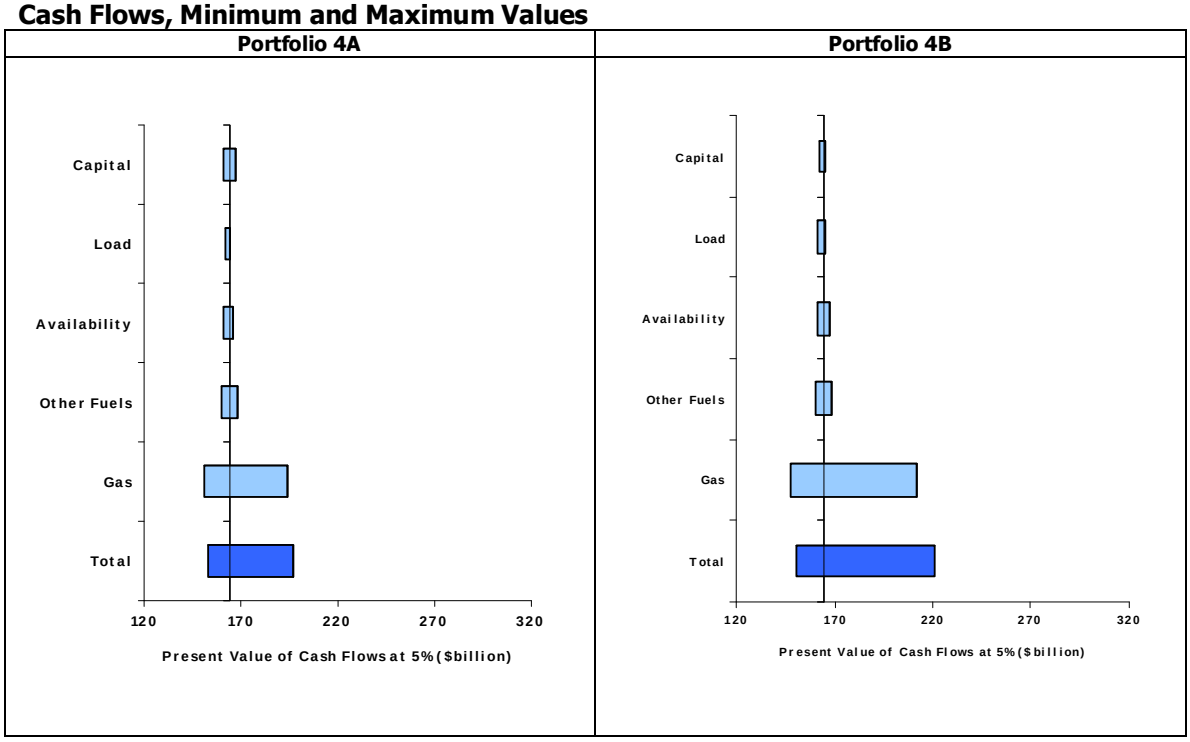
Figure 2.9.36 – Portfolios 4A and 4B - Indicative Volatility Contribution, Present Value of Cash Flows, Standard Deviation



	4a	4b
Capital	0.91	0.52
Load	0.36	0.52
Availability	0.65	0.92
Other Fuel	0.94	1.01
Natural Gas	6.46	9.43

Source: OPA

Figure 2.9.37: Portfolios 4A and 4B – Indicative Volatility Contribution, Present Value of Cash Flows, Minimum and Maximum Values



Source: OPA

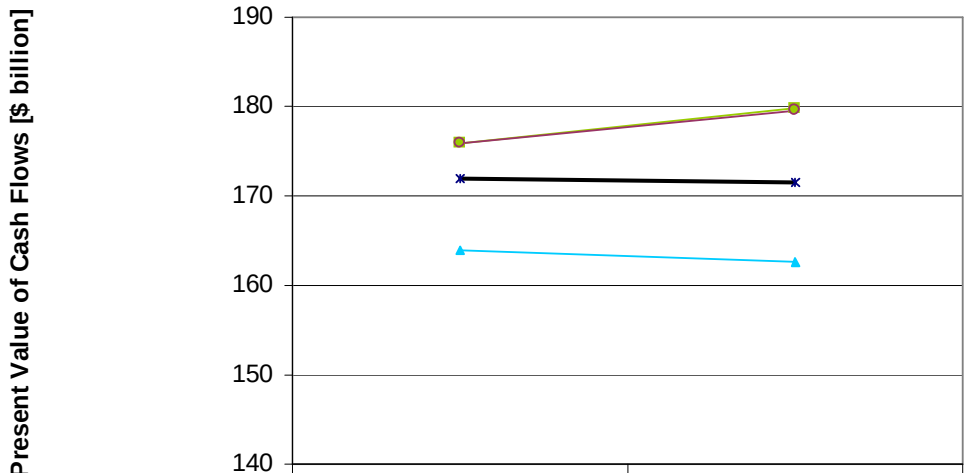
Figure 2.9.38 summarizes the results of the sensitivity studies applied to the Portfolios. Portfolio 4A shows a lower cost under the climate change and technology improvement sensitivities, while Portfolio 4B shows lower cost under the low natural gas price sensitivity.

2.9.6.3 Combined Cost, Risk, and Environmental Loading

Figure 2.9.39 summarizes the cost, risk and environmental loading score of Portfolios 4A and 4B.

Figure 2.9.39 indicates that Portfolio 4B, which relies more heavily on natural gas-fired generation, is more expensive than Portfolio 4A, entails greater risk and results in a higher environmental impact.

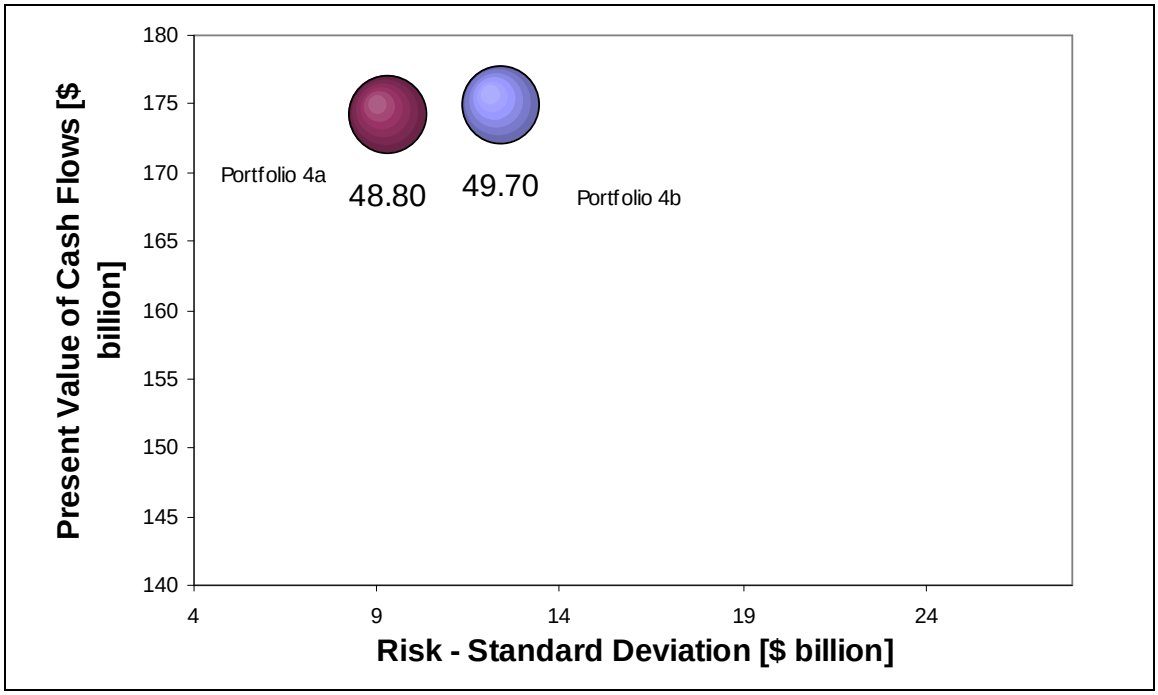
Figure 2.9.38: Portfolios 4A and 4B - Deterministic Sensitivity Analysis, Present Value of Cash Flows



	Portfolio 4a	Portfolio 4b
Deterministic Average	171.89	171.52
Climate change	175.95	179.83
Low Gas Price	163.89	162.57
Technology Improvement	175.92	179.55

Source: OPA

Figure 2.9.39 – Portfolios 4A and 4B – Cost/ Risk/Environmental Loading Score



Source: OPA

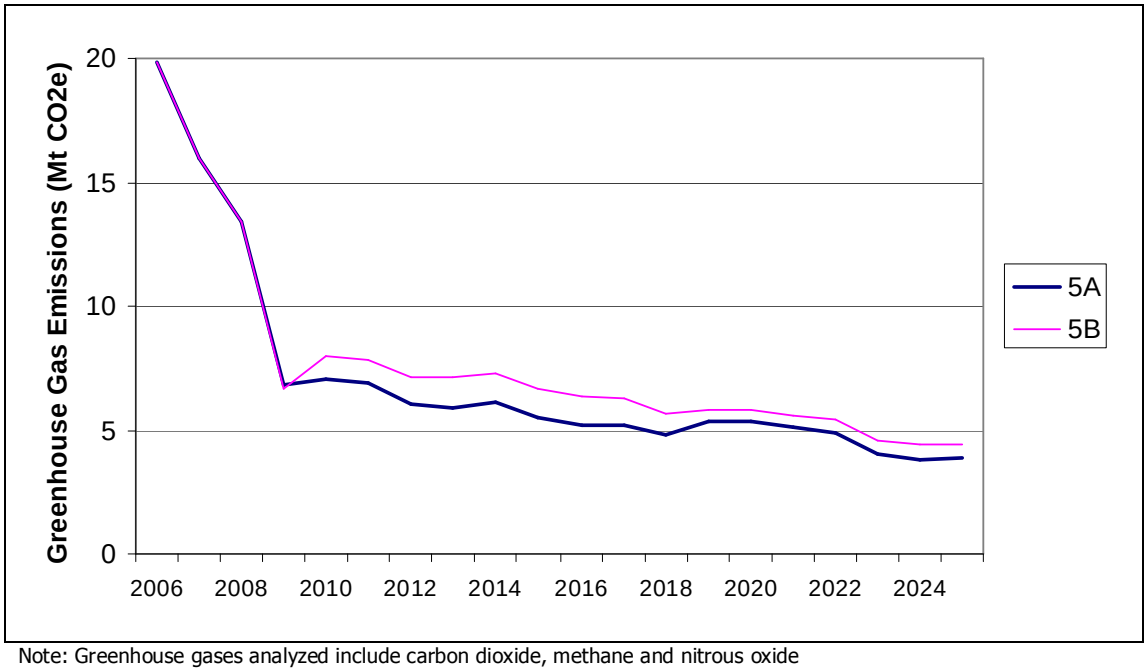
2.9.7 Scenario 5 (High Conservation)

2.9.7.1 Environmental Impacts

The annual greenhouse gas emissions for Portfolios 5A and 5B are shown in Figure 2.9.40. Portfolio 5B, with its higher use of natural gas-fired generation, results in higher greenhouse gas emissions. Total greenhouse gas emissions over the study period are 202 Mt CO_2e for Portfolio 4A, and 224 MT CO_2e for Portfolio 4B.

The environmental loading scores of the Portfolios during the study period and beyond, including the breakdown of the different contributions to the score, are shown in Figure 2.9.41. Portfolio 5A results in a lower environmental loading score than Portfolio 5B, and that this can be expected to be sustained in the longer-term. The absolute values associated with each portfolio are presented in Table 2.9.10.

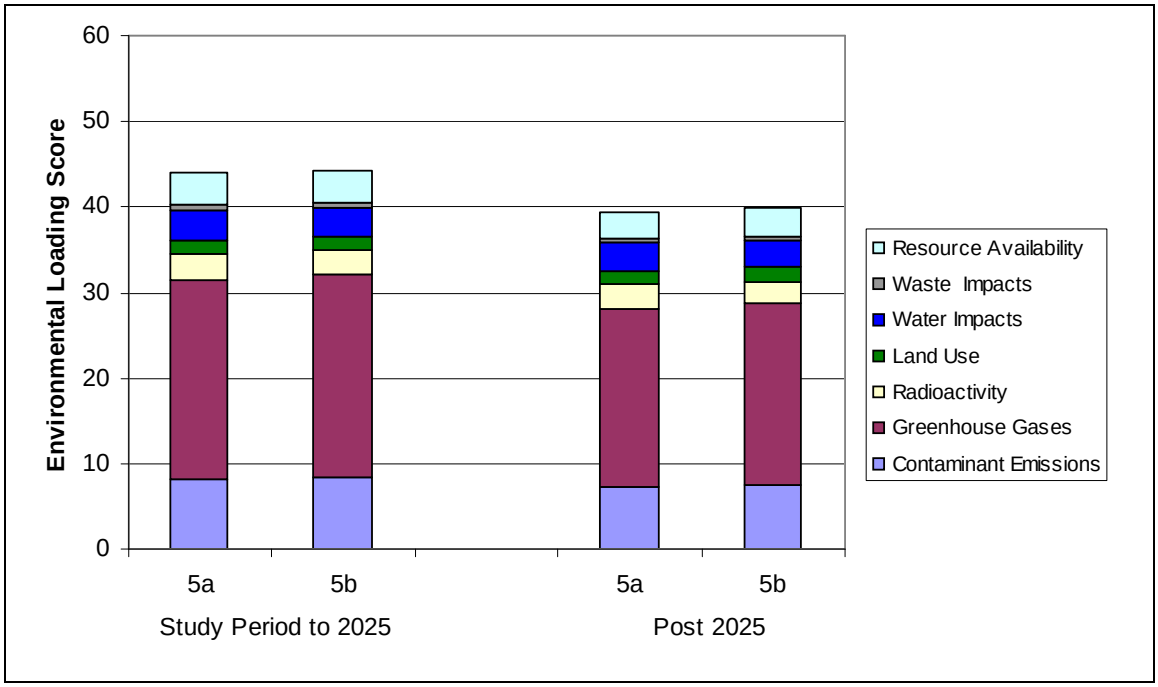
Figure 2.9.40 – Portfolios 5A and 5B - Annual Greenhouse Gas Emissions



Note: Greenhouse gases analyzed include carbon dioxide, methane and nitrous oxide

Source: OPA

Figure 2.9.41 – Portfolios 5A and 5B – Environmental Loading Scores by Impact



Source: OPA

Table 2.9.10 – Portfolios 5A and 5B - Absolute Environmental Loading Values

Indicator	Metric	Portfolio 5A	Portfolio 5B
Contaminant Emissions	kT	937	966
Greenhouse Gas Emissions	Mt CO2e	202	224
Radioactivity	Sv	2720	2721
Land Use	km2	1115.3	1114.7
Water Use – Withdrawal	TL	471	459
Water Use - Consumption	TL	2.65	2.64
Waste	kT	270	266

Source: SENES, OPA

2.9.7.2 Costs, Risks and Sensitivities

Figure 2.9.42 below shows the present value of cash flows. Portfolio 5A is less expensive on account of lower capital and fuel and variable OM&A costs.

Figure 2.9.43 presents capital expenditures for Portfolios 5A and 5B, totaling $42.2 billion and $42.9 billion, respectively on a present value basis. Table 2.9.11 outlines capital expenditures as spent. The expenditures are similar between the two Portfolios, for all but 7 years over the study period.

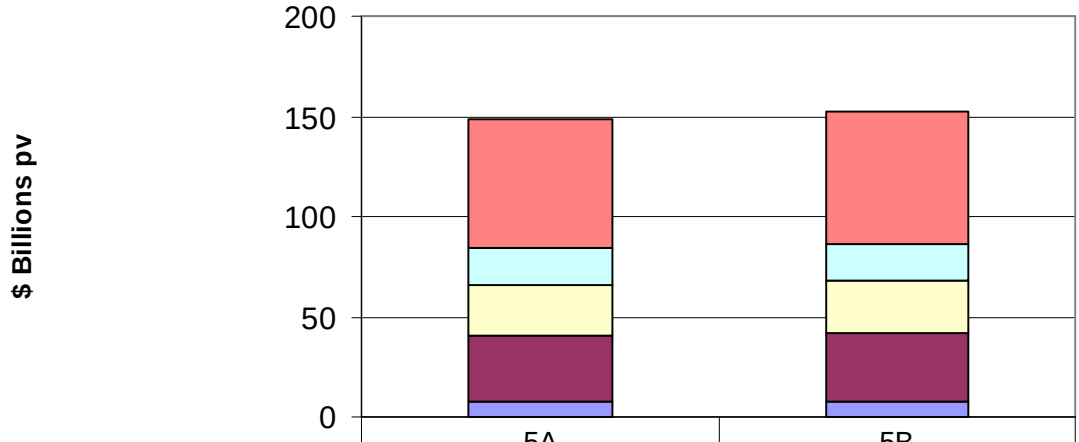
Figure 2.9.44 below shows the stochastic and deterministic average of the present value of cash flows for Portfolios 5A and 5B, together with the range in variability of the results. The range of variability around the expected costs is greater than the differences illustrated by both averages. In addition, Portfolio 5B has a larger range of variability.

Figure 2.9.45 illustrates the breakdown of the contributions to the variability around costs. In both Portfolios, natural gas price volatility is the largest contributor to cost risk. As Portfolio 5B relies more heavily on natural gas-fired generation, it exhibits greater variability around natural gas fuel price.

Whereas Figure 2.9.45 illustrates the standard deviation of results, Figure 2.9.46 illustrates the stochastic minimum and maximum values. Figure 2.9.46 shows that the risk spread of Portfolio 5B is greater than that of Portfolio 5A, and is principally driven by natural gas price risk.

Figure 2.9.47 summarizes the results of the sensitivity studies applied to the Portfolios. Portfolio 5A maintains its cost advantage across all sensitivities.

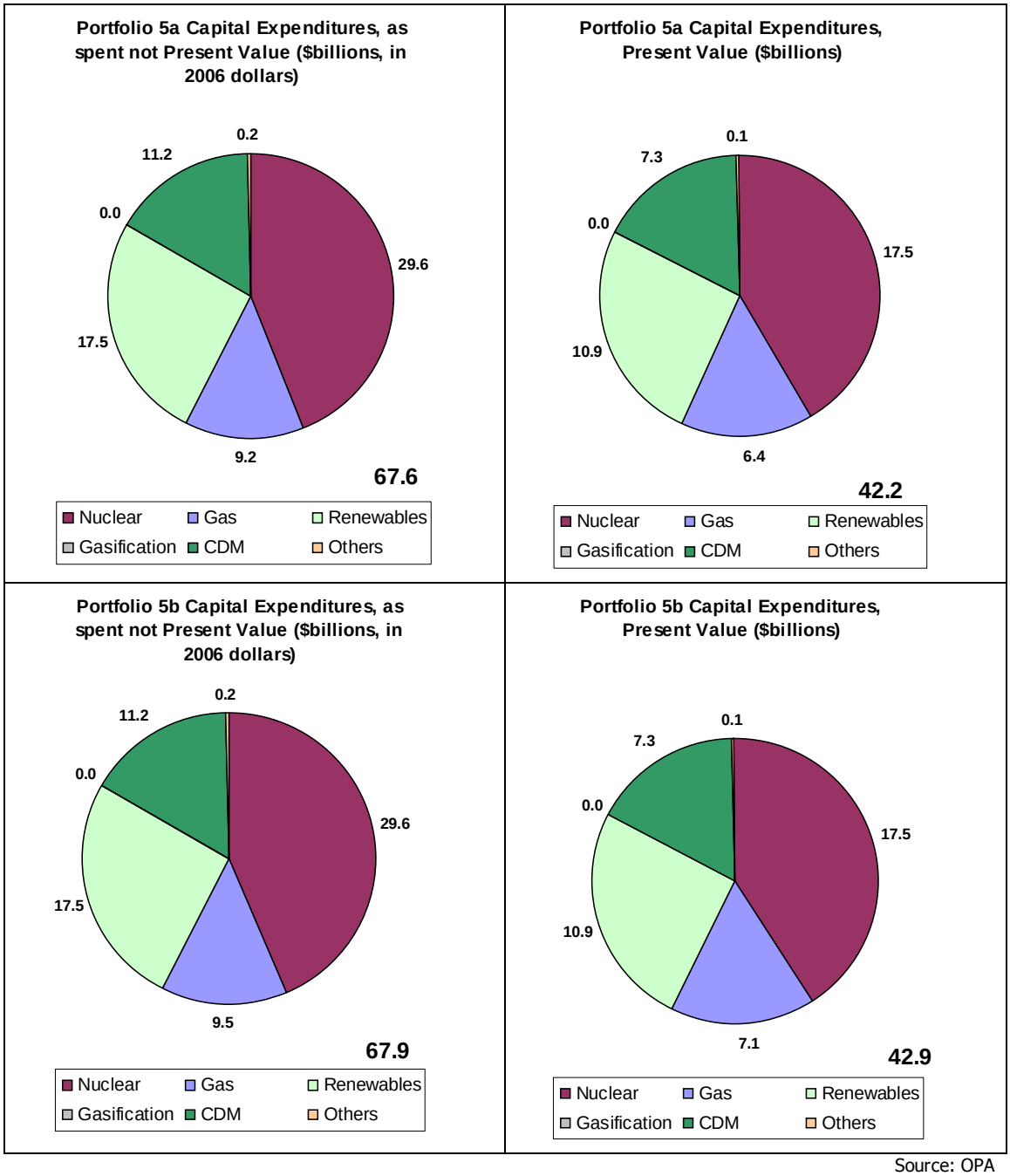
Figure 2.9.42 – Portfolios 5A and 5B - Present Value of Cash Flow Components



	5A	5B
Total	148	152
Long Term (Post 2025)	64	65
Capital Charged to Study Period	18	19
Fuel & Variable OM&A	25	27
Fixed OM&A	34	34
CDM	7	7

Source: OPA

Figure 2.9.43 – Portfolios 5A and 5B – Capital Expenditures



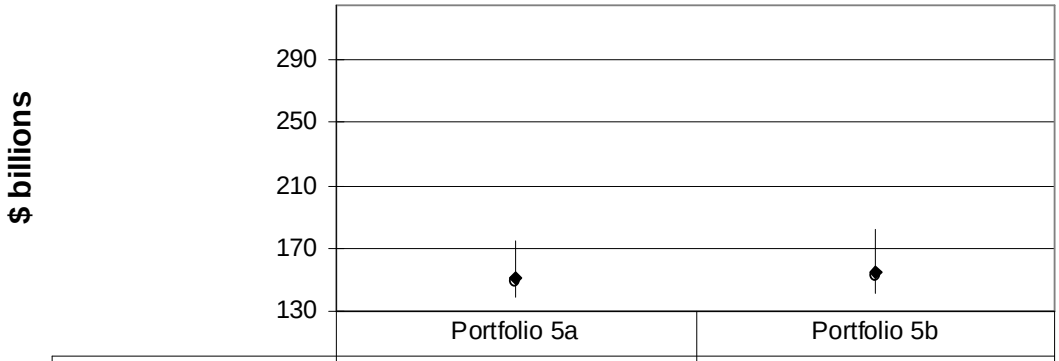
Source: OPA

Table 2.9.11 – Portfolios 5A and 5B – Annual Capital Expenditures, As Spent, not Present Value ($ Billions, 2006 Dollars)

Capital Expenditures 5a																					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	1.70	2.41	2.33	1.52	1.52	0.82	1.80	0.12	29.60
Gas	0.18	0.23	3.01	1.04	0.22	0.16	0.26	0.23	0.39	0.02	0.02	0.45	0.91	0.48	0.02	0.02	0.59	0.02	0.99	0.02	9.24
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.41	0.54	0.77	0.93	1.01	1.02	1.03	1.04	0.73	1.07	1.08	1.09	0.76	17.47
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CDM	0.06	0.16	0.31	0.51	0.75	1.02	1.24	1.34	1.27	1.17	0.89	0.54	0.63	0.34	0.27	0.23	0.19	0.13	0.08	0.03	11.16
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.81**	**3.01**	**3.68**	**6.05**	**4.57**	**2.26**	**1.63**	**2.09**	**6.12**	**2.84**	**5.83**	**3.70**	**4.27**	**4.27**	**3.67**	**2.51**	**3.38**	**2.06**	**3.96**	**0.94**	**67.64**
Capital Expenditures 5b																					
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**Total**
Nuclear	0.10	0.10	0.11	2.39	3.14	0.85	0.11	0.11	3.91	0.88	3.99	1.68	1.70	2.41	2.33	1.52	1.52	0.82	1.80	0.12	29.60
Gas	0.18	0.23	3.54	0.76	1.64	0.16	0.26	0.23	0.39	0.02	0.02	0.45	0.02	0.57	0.02	0.02	0.02	0.02	0.99	0.02	9.54
Renewables	0.44	2.49	0.24	2.11	0.44	0.23	0.02	0.41	0.54	0.77	0.93	1.01	1.02	1.03	1.04	1.06	0.74	1.08	1.09	0.76	17.47
Gasification	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CDM	0.06	0.16	0.31	0.51	0.75	1.02	1.24	1.34	1.27	1.17	0.89	0.54	0.63	0.34	0.27	0.23	0.19	0.13	0.08	0.03	11.16
Others	0.03	0.03	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.17
Total	**0.81**	**3.01**	**4.21**	**5.77**	**5.99**	**2.26**	**1.63**	**2.09**	**6.12**	**2.84**	**5.83**	**3.70**	**3.38**	**4.37**	**3.67**	**2.83**	**2.48**	**2.06**	**3.96**	**0.94**	**67.94**

Source: OPA

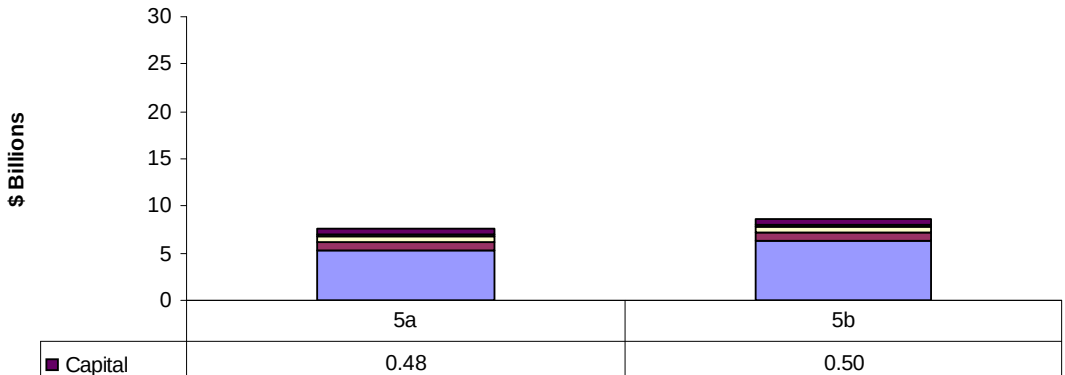
Figure 2.9.44 – Portfolios 5A and 5B - Present Value of Cash Flows



	Portfolio 5a	Portfolio 5b
Maximum	174.89	182.78
Minimum	139.30	141.73
◆ Stochastic Average	150.63	154.44
○ Deterministic Average	148.24	152.09

Source: OPA

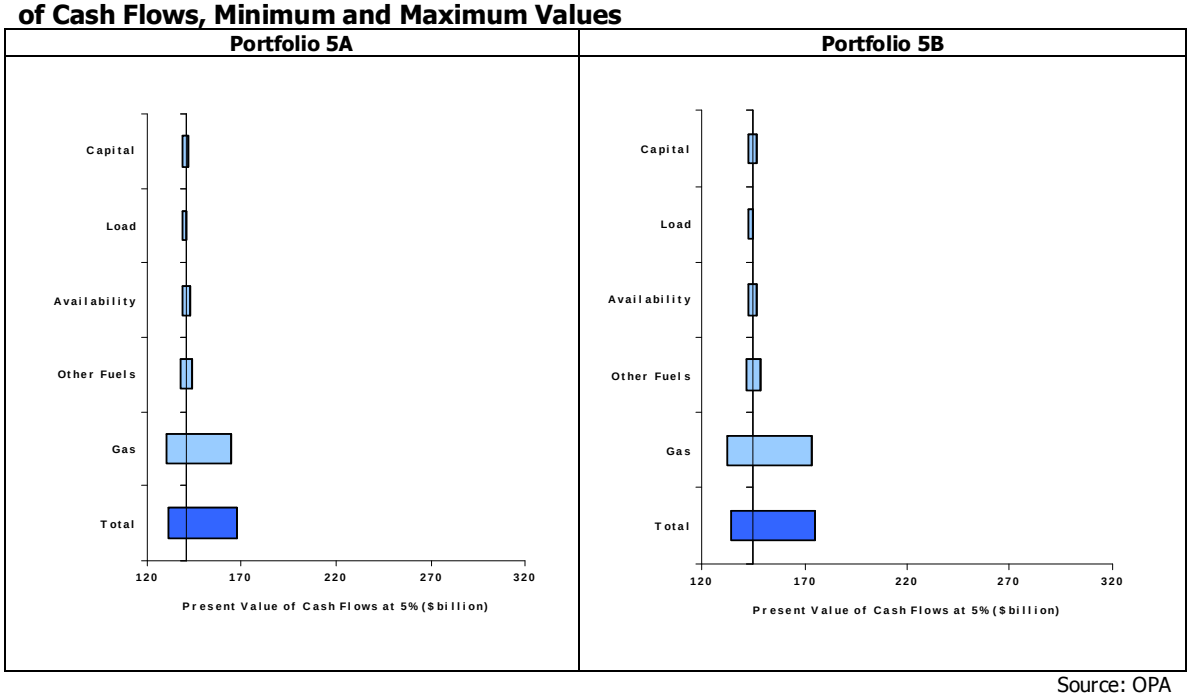
Figure 2.9.45 – Portfolios 5A and 5B - Indicative Volatility Contribution, Present Value of Cash Flows



	5a	5b
Capital	0.48	0.50
Load	0.31	0.31
Availability	0.56	0.53
Other Fuel	0.83	0.83
Natural Gas	5.34	6.42

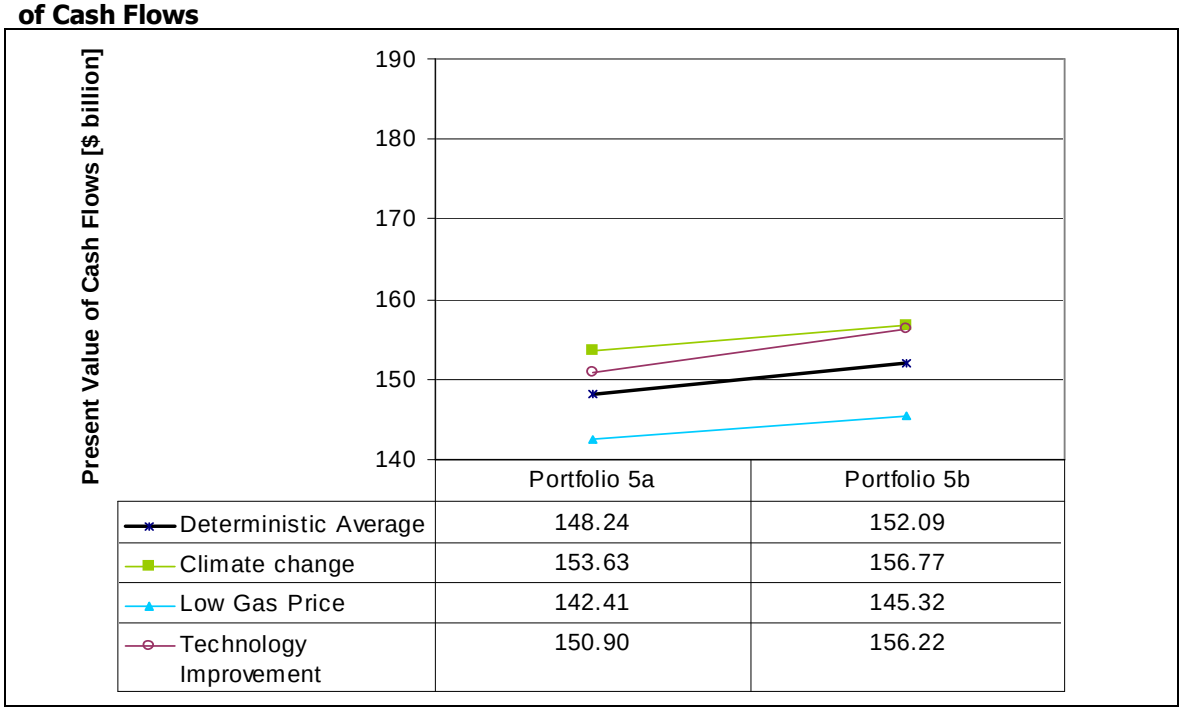
Source: OPA

Figure 2.9.46 – Portfolios 5A and 5B – Indicative Volatility Contribution, Present Value of Cash Flows, Minimum and Maximum Values



Source: OPA

Figure 2.9.47 – Portfolios 5A and 5B - Deterministic Sensitivity Analysis, Present Value of Cash Flows



	Portfolio 5a	Portfolio 5b
Deterministic Average	148.24	152.09
Climate change	153.63	156.77
Low Gas Price	142.41	145.32
Technology Improvement	150.90	156.22

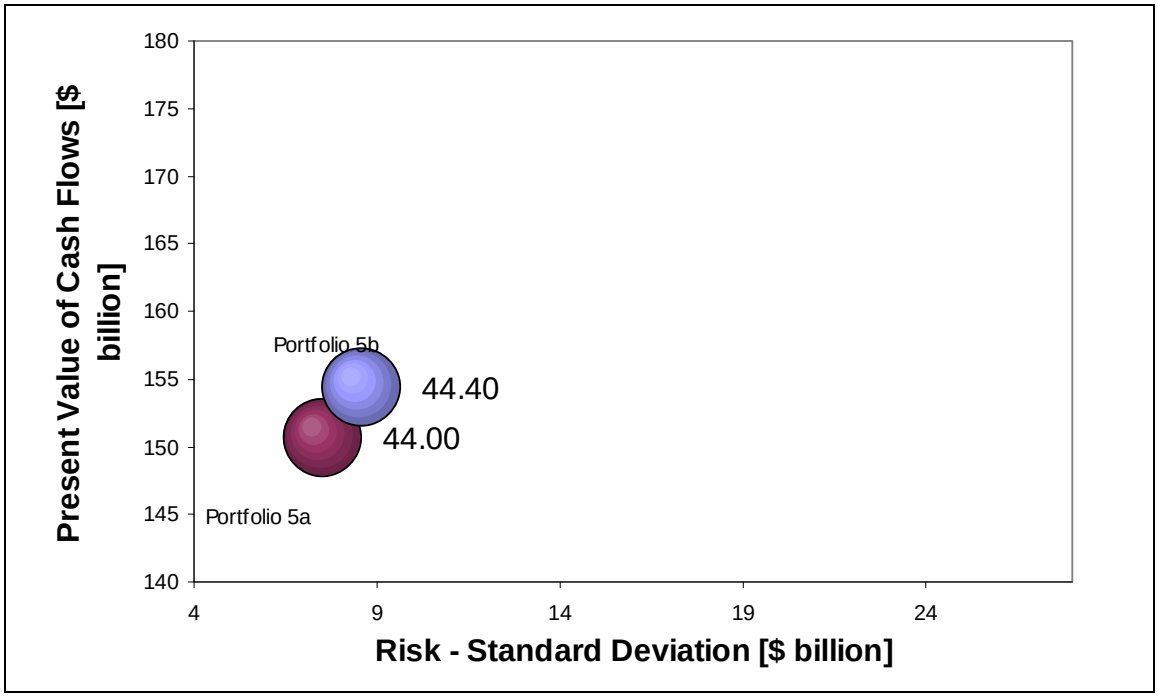
Source: OPA

2.9.7.3 Combined Cost, Risk, and Environmental Loading

Figure 2.9.48 summarizes the cost, risk and environmental loading score of Portfolios 5A and 5B.

Figure 2.9.48 indicates that Portfolio 5B, which does not recognize higher success in capturing conservation and demand management potential until 3 years from now, is more expensive than Portfolio 5A, entails greater risk and results in a higher environmental impact. The difference in costs shows an almost $4 Billion (present value) advantage for the early recognition of greater conservation and demand management potential. The analysis cannot capture, however, the variability around the cost and probability of obtaining the higher amounts of CDM.

Figure 2.9.48 – Portfolios 5A and 5B – Cost/ Risk/Environmental Loading Score



Source: OPA

2.9.8 Conclusion

The 10 portfolios described in Part 2.8 were analyzed from the perspective of environmental impact, cost and risk. Results of the analysis show that environmental impacts and costs are often similar between Portfolios, as many of the assumed

resources and costs are common and are not influenced by the policy decisions being investigated.

Results of the analysis illustrate that environmental impacts tend to be greater where there is greater use of fossil fuel-based resources. The greatest cost-related differences between portfolios is with respect to risk around cost. The above analysis shows the predominant driver of higher risk to be the price variability of natural gas. It follows that Portfolios with greater reliance on natural gas tend to exhibit the highest degrees of risk.

Further, it has been seen that early recognition of greater success in capturing conservation results in a marked cost advantage. In practice, early recognition will be of greatest value where there is sufficient flexibility to adapt to changing conditions and to take advantage of opportunities as they arise.

The analysis of the five scenarios, and sensitivities around them, confirms the merits of a diversified and flexible portfolio including conservation, nuclear generation for base load, natural gas-fired generation for selected uses such as peaking, and renewables for energy production. This analysis suggests, at a minimum, keeping nuclear capacity at its current level through refurbishments and "new-build", and adopting a "smart gas" strategy that takes advantage of the attractive features of natural gas while minimizing price risk. Adding renewables to the extent that is economically achievable will reduce environmental impact and risk.